Alternatives to Ontario Hydro's Generation Program

Middleton Associates

November 1977

miscellaneous publications

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EXECUTIVE SUMMARY

- The study addresses the question: "to what extent would it be possible to postpone the introduction of another large generating station after 1988, the date at which Darlington G.S. is expected to begin full operation, without any reduction in the services that the electrical energy would have provided?"

- To answer the question the end uses implicit in Ontario Hydro's load forecast are examined and savings related to each end use are estimated.

- The costs of constructing and operating the next four stations after Darlington G.S. are estimated and compared with the costs of reducing the requirement for these stations.

- The potential of various measures for reducing capacity requirements is estimated, together, where possible, with associated costs. Included are: industrial cogeneration, electricity from biomass, wind generated electricity, electricity from small hydraulic sources, interconnections, insulation of residential buildings, improved efficiency of residential appliances, energy conservation in the commercial and industrial sectors, solar space and water heating, district heating, load management.

- Implementation rates for the measures are assumed and the individual and combined energy and capacity savings are estimated.

PRINCIPAL FINDINGS

- The combined contribution of industrial cogeneration and increased levels of insulation in electrically heated homes could equal more than 3,800 mw by 1991, at a cost comparable with that of providing the same capacity from additional nuclear plants.

- The contribution of all the other measures could come to almost 7,500 mw by 1991.

- The total contribution of all these measures could exceed 10,000 mw by 1991 and 12,000 mw by 1993. This is equivalent to the capacity of the next four large generating stations that Ontario Hydro plans to bring into service after Darlington G.S.

- Technically and economically viable alternatives to the construction of large generating stations appear to be available to meet Ontario Hydro's forecast of electrical demand.

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Peter A. Victor

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CHAPTER I

INTRODUCTION: THE QUESTION POSED

1. PURPOSE OF THE STUDY

Throughout the world, many countries are reassessing their commitment to a rapidly expanding electrical energy generation program. Within Canada reassessment has proceeded furthest in Ontario where the Royal Commission on Electric Power Planning has been examining the long-range planning of Ontario's electric power system.

In the course of the Commission's inquiry numerous representations have been made regarding the possibility of reducing Ontario's dependence on electricity generated from centralized sources. Practices in other countries have been cited as examples of what is possible in Ontario and various studies, some of which were funded by the Commission, have examined specific options that would reduce the rate of growth of Ontario Hydro's generation program.

To date, insufficient attention has been paid to combining in a consistent manner the wide range of possibilities for reducing the amount of electricity to be supplied by Ontario Hydro. The purpose of the present study is to do this in the context of a specific question, the answer to which has implications for the more general problem of constructing alternative energy strategies for Ontario.

The question which provides the focus for the entire study is the following:

To what extent would it be possible to postpone the introduction of another large generating station after 1988, the date at which Darlington G.S. is expected to begin full operation, without any reduction in the services that the electrical energy would have provided?

2. A GENERAL STATEMENT OF METHODOLOGY

The response to this question has been developed in several stages and on the basis of some key assumptions which should be understood at the outset:

i) Ontario Hydro's forecast of the most probable load growth has been accepted without question[(1)]. The study examines alternative means of satisfying the specific set of end uses (e.g. heating, lighting, motive power) that are implicit in Ontario Hydro's load forecast. Whether or not these end uses are in fact the most likely and the most desirable for Ontario are matters worthy of consideration in their own right, but are not pursued here.

ii) Since Ontario Hydro does not make its own forecast of the uses to which electricity will be put, it has been necessary to make an end use forecast consistent with Ontario Hydro's total load forecast. This was accomplished in consultation with a limited group of knowledgeable people, and the methodology and results are described fully in the next chapter. The main purpose of this end use forecast is to provide a benchmark against which the adequacy of an alternative means of servicing these end uses can be judged. It is assumed that such an alternative should be capable of providing at a comparable cost the same services as Ontario Hydro's proposed expanded, electrical generation system.

iii) Ontario Hydro's estimates of the capital cost savings from the deletion of the first four stations after Darlington G.S. were obtained. To complete the picture, operation, maintenance and fuel savings were estimated on the basis of data provided by Ontario Hydro. Costs for transmission, distribution and decommissioning were not included. The resultant estimated total savings from not building the first four stations after Darlington G.S. are used to judge the cost-effectiveness of the alternatives considered in the study.

iv) Ontario's requirements for electricity from Ontario Hydro can be reduced by a more efficient use of the electricity, and by substituting energy from other sources for centrally generated electricity. Conservation measures include increased insulation of buildings, improved efficiency of

using electricity and load management. New and additional sources of energy include solar space and water heating, industrial cogeneration of electricity, wind power, and energy derived from biomass. All these and more are considered in this study in terms of energy savings, energy supply, and cost.

v) The final methodological step is to bring together all the pieces of information in the study that bear on the potential for postponing the construction of additional large electrical generation facilities after Darlington G.S., without foregoing any of the services that the electricity would have provided.

3. LIMITATIONS OF THE STUDY

Any study which deals with a period extending as much as 30 years into the future necessarily confronts a large measure of uncertainty, leaving room for substantial disagreement over the accuracy of the results obtained. The fact that this study is concerned with energy, a subject which is particularly prone to unforeseen technical problems and breakthroughs, unpredictable yet significant cost increases, and erratic political involvement, only serves to complicate the problem of analyzing future options and their consequences.

This is not to suggest that attempts to look into the future and make appropriate plans are not worthwhile. Indeed, the opposite conclusion should be drawn since planning is one way of dealing with uncertainty. What should be clearly understood, however, is that this particular

study provides an analysis of only one among a very large number of possible alternative energy mixes for Ontario. It deals with a very specific modification to Ontario Hydro's generation program, without, it should be recognized, considering the policy initiatives necessary for its implementation. As such the results should be regarded only as an indication of what is possible when something other than the business-as-usual approach is assumed. A somewhat broader approach, in which many of the assumptions listed earlier would be relaxed, will be necessary in order to develop a proper alternative energy strategy for the Province.

Even with the issues narrowed down to a response to a specific question, a wide range of assumptions has been required relating particularly to technical performance and cost. Choices have had to be made throughout and the practice has been to lean heavily on the conservative side so that one can be confident that, if anything, the conclusions of the study underestimate the scope for curtailing Ontario Hydro's expansion program.

As to the particular nature of the curtailment, stations are assumed to be eliminated entirely from the program rather than merely postponed. The possibility of altering the operations of the existing stations to partially compensate for the foregone additions to capacity has, in most instances, been left out of the computations. Similarly, when the load forecast by Ontario Hydro ultimately overwhelms the conservation and alternative energy supply measures no consideration is given to the likelihood that Ontario Hydro might resume its expansion program with smaller stations than those presently envisaged. This longer term effect on the expansion program of the alternatives described in this study could be very significant but is not dealt with here.

Other aspects which are not discussed relate to the problems of implementing the alternatives to Ontario Hydro's generation program. Central among these is the reallocation of large amounts of capital that would be required to finance many of the alternatives to the construction of large generating stations.

Perhaps the most serious limitation of this study stems from the inadequacy of the data upon which the calculations and conclusions are based. To a large degree this reflects the lack of interest that has been shown by all but a few pioneers in alternative energy strategies. What work has been done has generally not been funded in a manner comparable with such programs as Ontario Hydro's generation expansion plan. The literature abounds in conflicting and inconsistent views and results, and, in some cases, there are complete gaps. These circumstances have demanded that a considerable amount of judgement be exercised throughout this study(2).

In conclusion, for all the reasons stated, this study should be regarded only as indicative of what might be done in Ontario, and at what cost, to reduce the requirement for a rapidly expanding centralized electrical generation system. Beyond the observation that the scope is considerable and more than sufficient to justify further inquiries into alternative energy strategies, the study contains no specific recommendations.

FOOTNOTES*:

1. The most recent forecast at the time of the study was contained in Load Forecast 1977 by Regions and Marketing Branch, Ontario Hydro, April 1977. (41)

2. In some of the tables that appear in the study there may be minor discrepancies due to rounding errors.

*Bracketed numbers refer to the bibliography at the end of the report.

CHAPTER II

THE END USE OF ELECTRICITY IN ONTARIO, PAST AND FUTURE

1. INTRODUCTION

"End use" refers here to the specific services provided by the consumption of electricity. Typical end uses include space and water heating, cooking, lighting, air-conditioning, and operating motors for a wide variety of purposes. It has become customary to distinguish among the residential, commercial and industrial use of electricity and to analyze the end uses within each sector. This distinction is maintained in the present study.

Information about the end use of electricity and forecasts of the future end use are important for a number of purposes. In particular, the appropriateness of using electricity to perform specific tasks, such as the provision of space heating, can be evaluated using criteria derived from the physical laws of thermodynamics. Two approaches are commonly used. The first compares the heat value of the primary energy input (e.g. 25.4 million Btu per ton of coal) with the heat value obtained from running electricity through resistance heaters. A "first law efficiency" of 30% is not uncommon [1]. The second approach, based on the second law of thermodynamics, compares the use value or quality of the energy used to perform a certain task with the theoretical minimum quantity of energy that would perform the same task [2].

Using this criterion one estimate for energy consumed in the United States [3] suggested that eight-five percent of the capacity of this energy to do work is wasted.

The reason for this high level of waste, at least part of which, it should be noted, may not make economic sense to eliminate, is due to such practices as using a fission reaction at 10,000°C to obtain steam to drive a turbine which generates electricity that is transmitted over many miles so that it can be run through a resistance heater to raise room temperature by 10°C. In the absence of waste heat utilization, a practice which is still uncommon in Ontario, all the heat losses in this process of energy transformation constitute a waste of useful energy.

Whether or not the traditional economic criteria of cost effectiveness should be supplanted or supplemented by these physical measures of efficiency is a matter of current debate [4]. If the conclusion is that they should at least be considered as an addition to economic evaluation, as seems likely, then greater attention will have to be paid to the end use of electricity, and other forms of energy, than has been the case in the past.

In the context of this study, concerned as it is with the possibility of doing without certain planned additions to Ontario Hydro's generating capacity, a forecast of the end use of the electricity to be displaced is essential if equivalent services are to be provided by alternative means. For example, the expected use of electricity for space heating places an upper limit on the extent to which electricity can be saved by means of increased insulation of buildings and by the widespread introduction of solar heating.

In a discussion related to alternative energy strategies, given the importance of forecasting not only the total demand for electricity but also its expected end use, it is significant that no systematic end use forecasts have been made by Ontario Hydro or by the Ministry of Energy.

This undoubtedly reflects their orientation towards a supply approach to energy policy, which accepts the demand for specific forms of energy as given and seeks only ways to satisfy the demand. In contrast, this study recognizes that this demand for energy can provide services, and only accepts the demand for services as given. It is this perspective which leads directly to a consideration of other means of providing the same services. A further step, and one not taken in this study, would be to examine and evaluate the services that are demanded and to look at ways and means of modifying these demands as part of an overall energy strategy.

For the purposes of this study, the lack of an official end use forecast for electricity in Ontario meant that such a forecast had to be made. The rest of this chapter describes the methodology used and the results obtained.

2. FORECASTING THE END USE OF ELECTRICITY IN ONTARIO

A forecast of the end use of electricity in Ontario for the next thirty years was obtained by soliciting responses to a questionnaire from eight individuals actively engaged in making, criticizing, or implementing Ontario's electricl energy policy[(5)].

Historical end use data was provided together with Ontario Hydro's forecast of the most probable load growth and a statement of the principal assumptions on which this forecast was based. For further information, a graphical projection of end uses up to 2007 based on 1976 data was also made available. The questionnaire and all the supplementary material are contained in Appendix A of this report.

The respondents were explicitly told to accept Ontario Hydro's load forecast as being the most probable and to consider only how the electricity would be used were it to be demanded in the amount forecast.

Initial responses to the questionnaire were surprisingly similar given the very different perspectives of the various participants. The averages and standard deviations of the seven responses to each question were circulated to the respondents who were given the opportunity to revise their forecasts [6]. In almost every case the standard deviations declined, indicating a reduction in the range of the individual responses. The arithmetic average and standard deviation of these second round responses are shown in tables II.1 to II.4.

The averages displayed in the tables were accepted for the purposes of this study as a reasonable end use forecast that is consistent with Ontario Hydro's forecast of load growth.

TABLE II.1

PROJECTED USE OF ELECTRICITY BY SECTOR (PERCENT)

	HISTORICAL			PROJECTED[1]		
SECTOR	1966	1971	1974	1987	1997	2007
Residential	28.8	31.0	31.4	30.9,(1.7)	30.3,(4.5)	28.3,(6.4)
Commercial	20.3	22.4	27.2	27.6,(2.2)	27.7,(4.7)	27.3,(6.2)
Industrial	50.9	46.6	41.4	41.6,(3.1)	42.6,(4.8)	44.4,(7.4)
Total	100.0	100.0	100.0			

1. Standard deviations of responses in parentheses

Source: Historical data from Ontario Hydro, Energy Utilization and the Role of Electricity, 1976 (26)

TABLE II.2

PROJECTED END USE OF ELECTRICITY IN THE RESIDENTIAL SECTOR (PERCENT)

	HISTORICAL				PROJECTED		
END USE	1951	1961	1971	1974	1987	1997	2007
Misc.	8.2	5.3	5.4	7.3	12.5,(11.7)	14.8,(16.9)	17.3,(21.7)
Clothes Drying	0.0	2.7	4.1	4.3	4.5,(.6)	4.4,(.8)	4.3,(.8)
Air Cond.	0.0	0.0	0.7	1.0	1.7,(.5	2.5,(1.0)	3.0,(1.6)
TV	2.8	4.5	4.8	5.2	4.4,(1.6)	4.4,(2.1)	4.2,(2.9)
Lighting	15.6	10.4	8.6	7.7	6.9,(3.2)	7.1,(4.4)	7.4,(5.9)
Stove Cooking	13.9	12.2	11.4	10.7	8.9,(3.6)	9.0,(4.4)	8.7,(5.6)
Refrigeration	6.7	9.4	14.8	13.8	11.4,(3.9)	10.3,(3.5)	9.0,(3.6)
Space Heating	5.3	4.7	17.8	20.2	23.7,(4.5)	26.0,(9.1)	29.3,(16.2)
Water Heating	47.5	50.8	32.4	29.8	26.0,(1.1)	21.5,(2.7)	16.9,(5.0)
Total:	100.0	100.0	100.0	100.0			

Source: Historical data from Ontario Hydro, Energy Utilization and the Role of Electricity, 1976 (26)

TABLE II.3

PROJECTED END USE OF ELECTRICITY IN THE COMMERCIAL SECTOR (PERCENT)

	HISTORICAL	PROJECTED		
End Use	1974	1987	1997	2007
Motors	51.0	51.9,(1.2)	51.5,(3.9)	50.3,(7.7)
Heating	5.8	7.1,(1.7)	10.0,(5.4)	12.9,(9.4)
Lighting	38.8	35.3,(2.7)	31.4,(3.6)	29.1,(3.9)
Other	4.4	5.7,(.8)	7.1,(1.7)	7.7,(2.5)
TOTAL	100.0			

Source: Historical data from Ontario Hydro, Energy Utilization and the Role of Electricity, 1976 (26)

TABLE II.4

PROJECTED END USE OF ELECTRICITY IN THE INDUSTRIAL SECTOR (PERCENT)

	HISTORICAL	PROJECTED		
End use	1974	1987	1997	2007
Motors	76.1	75.1,(1.0)	73.0,(3.4)	70.0,(8.9)
Heating	13.7	14.5,(1.1)	17.0,(4.8)	19.9,(10.8)
Lighting	10.2	9.4,(1.0)	8.6,(2.0)	7.9,(2.8)
Other	0.0	1.0,(1.4)	1.4,(1.6)	2.2,(2.1)
Total	100.0			

Source: Historical data from Ontario Hydro, Energy Utilization and the Role of Electricity, 1976 (26)

In order to convert these projections in percentage terms for the years 1987, 1997 and 2007 into projections of energy use for each year, 1975-2007, the averages in tables II.1 to II.4 were applied to Ontario Hydro's load forecast and plotted. The points were joined and readings were taken of the end use of electricity in each of the sectors. In each case 'other' uses were computed as a residual after the total electricity use in each sector was divided among the specified uses. It is recognised that this methodology is not especially rigorous but was the most appropriate in the time available. The numerical results are displayed in tables II.5 to II.7.

TABLE II.5

ESTIMATED END USE OF ELECTRICITY IN THE RESIDENTIAL SECTOR
(10^6 mwh)

YEAR	WATER HEATING	SPACE HEATING	REFRIG-ERATION	COOKING	LIGHTING	TV	AIR COND.[1]	DRYING	MISC.	TOTAL
1977	8.0	6.5	4.8	2.8	1.6	.8	.9	1.4	2.0	28.8
1978	8.4	6.9	4.8	3.1	2.0	.8	1.0	1.6	2.2	30.8
1979	9.0	7.7	5.3	3.4	2.0	.8	1.0	1.6	2.4	33.2
1980	9.3	8.1	5.3	3.6	2.4	.8	1.0	1.6	2.7	34.8
1981	10.2	8.9	5.5	3.8	2.4	.9	1.0	1.8	3.1	37.6
1982	10.8	9.7	5.6	4.0	3.2	1.1	1.0	2.0	3.5	40.9
1983	11.2	10.2	5.6	4.0	3.2	1.2	1.0	2.4	4.0	42.8
1984	12.0	11.0	6.0	4.2	3.2	1.2	1.0	2.4	4.4	45.4
1985	12.8	11.8	6.0	4.3	3.5	1.6	1.0	2.4	4.8	48.2
1986	13.4	12.2	6.6	4.7	3.8	1.6	1.0	3.0	5.4	51.7
1987	14.0	12.8	6.8	4.8	3.8	2.0	1.0	3.0	6.4	54.6
1988	14.6	13.8	7.2	4.8	4.0	2.4	1.0	3.0	7.3	58.1
1989	15.4	15.0	7.2	4.8	4.8	2.4	1.0	3.0	8.1	61.7
1990	16.0	16.3	7.6	5.0	5.4	2.4	1.0	3.2	8.8	65.7
1991	16.9	17.9	7.8	5.3	6.0	2.5	1.0	3.2	9.4	70.0
1992	17.6	18.7	8.0	5.6	6.4	2.5	1.1	3.6	10.4	73.9
1993	18.4	20.3	8.4	6.2	6.4	2.5	1.1	4.0	11.2	78.5
1994	18.8	21.5	8.8	6.6	6.6	2.8	1.2	4.0	11.9	82.2
1995	19.5	23.0	9.2	7.2	6.6	3.2	1.2	4.0	12.5	86.4
1996	20.0	24.4	9.5	8.0	6.6	4.0	1.2	4.0	13.6	91.3
1997	21.0	25.4	9.8	8.8	6.7	4.4	1.3	4.2	14.4	96.0
1998	21.6	27.6	10.1	9.6	6.8	4.8	1.3	4.2	15.2	101.2
1999	22.2	29.7	10.8	10.0	7.2	5.0	1.4	4.8	16.0	107.1
2000	22.8	31.3	11.2	10.4	7.6	5.3	1.4	4.8	16.8	111.6
2001	23.6	33.3	11.6	10.8	7.6	5.6	1.5	5.0	17.6	116.6
2002	24.2	35.8	12.0	11.2	8.0	5.6	1.5	5.0	18.8	122.1
2003	25.0	37.8	12.4	12.0	8.2	6.0	1.5	5.0	20.0	127.9
2004	25.8	39.7	12.8	12.6	9.4	6.0	1.6	5.6	21.6	135.1
2005	26.4	42.7	13.2	13.2	10.0	6.4	1.6	5.6	23.2	142.3
2006	27.1	45.5	14.2	13.8	10.8	6.4	1.6	5.6	24.8	149.8
2007	27.8	47.3	14.4	14.2	12.2	6.4	2.0	6.4	28.0	158.7

1. Obtained by subtracting all other uses from the total

TABLE II.6

ESTIMATED END USE OF ELECTRICITY IN THE COMMERCIAL SECTOR

(10^6 mwh)

YEAR	MOTORS	HEATING	LIGHTING	OTHER	TOTAL
1977	12.9	1.7	9.1	0.3	24.0
1978	13.7	1.9	9.7	1.1	26.4
1979	14.5	2.0	10.4	1.9	28.8
1980	15.3	2.1	11.0	2.0	30.4
1981	16.9	2.3	11.7	2.7	33.6
1982	17.7	2.5	12.6	2.4	35.2
1983	19.3	2.6	13.6	1.3	36.8
1984	20.9	2.8	14.3	2.0	40.0
1985	22.5	2.9	14.9	1.3	41.6
1986	24.1	3.2	16.2	1.3	44.8
1987	25.0	3.4	16.9	2.7	48.0
1988	27.4	3.5	17.8	2.5	51.2
1989	29.0	3.8	18.8	2.8	54.4
1990	30.6	4.0	20.1	2.9	57.6
1991	33.0	4.3	21.4	2.9	61.6
1992	35.4	4.5	22.7	3.0	65.6
1993	37.0	4.8	24.0	3.8	69.6
1994	38.7	5.1	25.3	4.5	73.6
1995	41.9	5.4	26.6	4.5	78.4
1996	43.5	5.7	28.6	5.4	83.2
1997	46.4	7.2	29.9	6.1	89.6
1998	48.3	8.2	31.5	6.4	94.4
1999	51.6	7.7	33.1	6.8	99.2
2000	54.0	7.8	35.1	7.1	104.0
2001	56.4	9.4	37.0	7.6	110.4
2002	60.4	9.3	39.0	8.1	116.8
2003	63.7	10.2	40.9	8.4	123.2
2004	66.9	11.9	43.5	8.9	131.2
2005	70.9	11.7	45.5	9.5	137.6
2006	75.0	14.0	48.1	10.1	147.2
2007	79.0	16.8	50.3	10.7	156.8

TABLE II.7

ESTIMATED END USE OF ELECTRICITY IN THE INDUSTRIAL SECTOR

(10^6 mwh)

YEAR	MOTORS	HEATING	LIGHTING	OTHER	TOTAL
1977	29.3	5.6	3.6	0	38.5
1978	31.2	5.8	3.8	0	40.8
1979	32.7	6.4	4.1	0	43.2
1980	35.3	6.6	4.4	0	46.3
1981	37.7	7.1	4.7	0	49.5
1982	40.8	7.6	5.0	0	53.4
1983	43.1	8.1	5.3	0	56.5
1984	46.0	8.7	5.7	0	61.2
1985	49.5	9.2	5.9	0.1	64.4
1986	51.9	9.8	6.3	1.1	69.1
1987	54.3	10.5	6.8	0.7	72.3
1988	58.2	11.2	7.2	1.9	78.5
1989	62.2	12.0	7.6	1.5	83.3
1990	66.2	12.8	8.1	0.9	88.0
1991	70.2	13.7	8.5	1.9	94.3
1992	75.0	14.5	9.1	0.4	99.0
1993	79.0	15.6	9.7	2.5	106.8
1994	84.6	16.6	10.3	1.6	113.1
1995	89.4	17.6	11.0	1.4	119.4
1996	94.2	18.4	11.6	3.1	127.3
1997	100.6	19.7	12.5	2.3	135.1
1998	105.4	21.0	13.2	3.4	143.0
1999	111.7	22.2	13.9	3.0	150.8
2000	118.1	23.3	14.8	4.1	160.3
2001	124.5	24.7	15.5	5.0	169.7
2002	130.9	26.3	16.5	7.0	180.7
2003	138.9	27.4	17.5	7.9	191.7
2004	146.9	29.4	18.6	7.8	202.7
2005	154.9	31.2	19.8	9.4	215.3
2006	164.4	33.5	20.9	13.8	232.6
2007	175.6	36.3	22.9	15.1	249.9

3. THE END USE OF ELECTRICITY: ENERGY AND POWER

This discussion so far has been concerned with forecasting the electrical energy requirements for specific end uses that are implied by Ontario Hydro's load forecast. Another characteristic of these end use requirements that is extremely important in energy planning is the daily, monthly, seasonal and annual load pattern. The degree of variation in the demand for electricity influences the best mix of different types of generating technologies since it is far easier and less costly to provide energy in amounts which fluctuate significantly over relatively brief periods by some means rather than others. According to Ontario Hydro, nuclear energy is presently the cheapest means of supplying unchanging amounts of base load. The various types of fossil-fuelled plants and hydro plants are brought in as needed to meet energy demands in excess of the base load.

The demand for energy varies over time and a useful distinction may be made between the average load and the peak load in any specific time period. The peak load is the highest instantaneous delivery of power in the period, though it is usually measured in terms of the greatest amount of energy demanded in any 20 minute period [7]. The load factor is defined as the ratio of the average load to the peak load and is usually expressed as a percentage.

The importance of this distinction between peak load, a measure of power, and average load (per hour), a measure of energy, is that it is the peak load of the system rather than the average

system load which governs the amount of installed capacity that electrical utilities must have if they are to avoid shortfalls in electricity supply.

Consequently alternative means of meeting the same end uses will permit reductions in capacity only to the extent that they affect the coincident peak demand for electricity. This may be done merely by inducing a change in the time that electricity is used so that the total use of electrical energy is unaffected, and hence, end uses measured over the year are maintained. This is known as load management and its scope for Ontario is considered in Chapter V.

All other means of maintaining the same end uses while curtailing Ontario Hydro's generation program, tend to affect the coincident peak demand for electricity somewhat indirectly. Much depends on the particular end use. For example, the substitution of solar water heating for electrical water heating removes a requirement for electrical energy that extends unevenly throughout the year. Given that the system peak demand for electricity occurs in Ontario in the midst of winter, a reduction in the demand for electrical energy used in the summer for heating water is of very little consequence for the rate of expansion of generating capacity. Reduction in the system peak demand is therefore critical. Although solar water heating offers year-round savings in electrical energy use, the important consideration is its contribution to reducing peak demand.

The lack of any official forecast of the end uses of electricity in Ontario is accompanied by a lack of an offical

forecast of the contribution that each end use of electricity is expected to make to the coincident peak demand for electricity. In the absence of such a forecast it has been assumed in this study, unless otherwise stated, that the annual load factor associated with the demand for electricity for each of the end uses identified earlier based on historical data, will not change in the future.

This assumption makes it possible to transform an estimate of electrical energy savings, attributable to any of the measures considered subsequently, into an estimate of the reduction in coincident peak demand[8].

FOOTNOTES:

1. American Institute of Physics, Conference Proceedings No. 25, Efficient Use of Energy, 1975 (1)

2. American Institute of Physics, Efficient Use of Energy, 1975, (1)

3. B. Commoner, The Poverty of Power, 1976 (7)

4. G. Winstanley, Energy Analysis: Methods, Uses, Implications, 1976 (60)

5. Those people consulted were associated with the following organizations: the Ontario Ministry of Energy, the Ontario Ministry of Treasury, Economics and Intergovernmental Affairs, Energy Probe, York University (2), the Royal Commission on Electric Power Planning (2). The employee of Ontario Hydro who was invited to participate, declined.

6. Unfortunately it was not possible to arrange a face-to-face meeting among the respondents, though it might have been helpful to do so. It is worth noting that several of them expressed difficulty in accepting Ontario Hydro's load forecast as reasonable.

7. For example, 5,000 mwh delivered in twenty minutes represents a peak load of 15,000 mw.

8. Load management will tend to change the system load factor. However, this adjustment yields figures directly of power reduction and is assumed not to affect the power-from-energy calculation.

CHAPTER III

FINANCIAL SAVINGS FROM POSTPONING THE INTRODUCTION OF LARGE CENTRAL GENERATING FACILITIES BEYOND 1987

I. INTRODUCTION

This chapter examines the financial savings that can be obtained by eliminating from Ontario Hydro's generation program all units of the first four large generating stations, planned to begin service from July 1987 to January 1993. All of these stations are in Ontario Hydro's East System program. In accordance with the wishes of the Commission, consequences of eliminating the two 200 mw units from the West System program with planned in-service dates in 1987 and 1989 are not considered because of their relatively small size.

The cost savings which are estimated fall into three major categories: capital costs, including interest on borrowed funds; operating and maintenance costs; fuel costs. In addition,elimination of nuclear plants affects the time at which new or expanded heavy water production facilities must be brought into service. This factor is accounted for in the capital cost estimates contained in this chapter. Elimination of generating stations from the system expansion plan would also reduce the requirements for additional transformer stations, transmission and distribution facilities.

These savings have not been estimated since they depend critically on plant locations, which have not been determined for plants to be built after Darlington G.S. This omission from the capital cost savings could be quite substantial. Ontario Hydro reports that the cost of installing transmission towers ranges from $300,000 - $493,000 per mile for 230 kw double circuit lines, depending on the type of tower, and from $600,000 - $1,000,000 for 500 kw double circuit lines(1). As a rough guide, an Ontario Hydro employee suggested that transformer station, transmission and distribution costs are one third the costs of generation stations. Furthermore, savings from reductions in reserve capacity and reduced decommissioning costs following the deletion of one or more large generating stations from Ontario Hydro's generation plan have not been estimated owing to the lack of information.

In sections 2, 3 and 4 of this chapter, the various assumptions necessary for estimating the cost savings are explained in detail. Section 5 describes the estimates of the cost savings as displayed in a series of accompanying tables.

2. ESTIMATED CAPITAL COSTS OF ONTARIO HYDRO'S GENERATION PROGRAM LRF 48A AND CAPITAL SAVINGS ACHIEVED BY ELIMINATING STATIONS FROM THIS PROGRAM

As of writing, Ontario Hydro's current generation expansion program is LRF 48A. A copy of this program appears as

Appendix B to this report. The program deals separately with the East and West systems, specifies the in-service date for each unit in the multi-unit stations that are planned, states whether the station will be nuclear or fossil (i.e. coal), gives the capacity of each unit.

The estimated annual capital expenditures associated with LRF 48A in current dollars are shown in figure III.1. Figure III.1. also shows the effect on these annual capital expenditures of deleting from one to four of the East system stations that are planned to follow Darlington G.S. These estimates, which were all prepared by Ontario Hydro, include reductions in the capital expenditures of the heavy water program which complements the nuclear component of LRF 48A.

It is apparent from figure III.1. that the reduction in capital expenditures is substantially greater for the deletion of a nuclear station than for a fossil station. This reflects the much greater capital costs of nuclear stations.

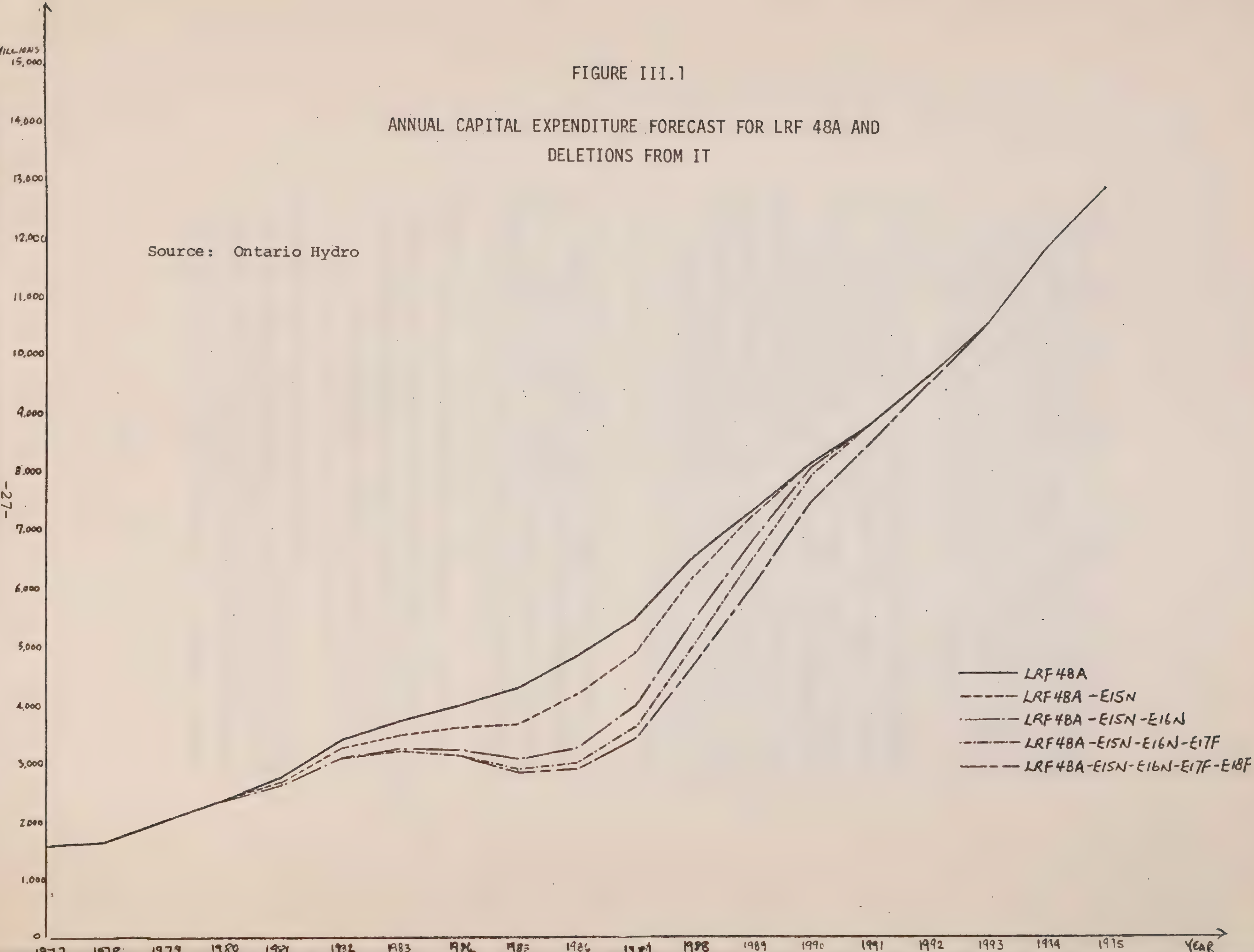
Figure III.1. is based on the assumption that stations are eliminated entirely rather than postponed. This is why, in each case, the annual capital expenditures eventually return to the level estimated for LRF 48A.

However, it is more likely that stations would neither be simply eliminated nor postponed in response to increased energy conservation and the development of alternative energy supplies. The lasting impact of these measures

FIGURE III.1

ANNUAL CAPITAL EXPENDITURE FORECAST FOR LRF 48A AND DELETIONS FROM IT

Source: Ontario Hydro



would be the resumption of capacity expansion by Ontario Hydro at a lower rate than that of LRF 48A. This could mean that smaller stations than the East system program presently includes would be required when additional capacity becomes necessary. A consideration of this interesting possibility was beyond the scope of the present study and the elimination of stations rather than their postponement was assumed to simplify the cost computations.

3. ESTIMATED OPERATION AND MAINTENANCE COST SAVINGS RESULTING FROM THE ELIMINATION OF NUCLEAR AND COAL-FIRED STATIONS

Whereas the elimination of a plant offers capital savings that extend over a decade, savings for operation and maintenance last the lifetime of the plant, some 30 years or more. Estimated annual operation and maintenance costs have been published by Ontario Hydro[2]. The graph, a copy of which appears as Appendix C to this report, is in terms of 1985 dollars[3], and should be used by multiplying the cost figure by the appropriate unit size[4].

By adopting this procedure estimates of operation and maintenance costs for the four stations (to follow Darlington G.S.) were obtained and are shown in table III.1.

TABLE III.1

ESTIMATED ANNUAL OPERATION AND MAINTENANCE COSTS (1985 DOLLARS) OF CANDU NUCLEAR AND COAL FIRED PLANTS

PLANT IN[1] LRF 48A	TYPE	UNIT SIZE (mw)	OPERATION AND MAINTENANCE COST ($/kw)
E15	Nuclear	516	$20.00
E16	Nuclear	850	12.50
E17	Coal	750	10.00
E18	Coal	750	10.00

1. Each of the plants consist of 4 units of the stated size.

Source: Ontario Hydro, Generation - Technical, Figure 2.1 8-2. (40)

These figures were used to estimate the operation and maintenance cost savings achieved by eliminating plants from LRF 48A. The savings were estimated in terms of current dollars for direct comparability with the capital cost savings described in section 2. Ontario Hydro's escalation factors were used for this purpose[5].

4. FUEL COSTS FOR NUCLEAR AND COAL-FIRED PLANTS

The estimated cost of fuel for generating electricity in a CANDU unit of at least 500 mw using a 37 element fuel bundle is \$1.4/mwh[6]. This compares with a cost of \$10.5 per mwh for coal-fired plants, 500 mw and larger[7]. Both figures are in 1976 dollars.

In order to estimate the fuel costs that will be avoided with the elimination of additional stations from Ontario Hydro's generation program, assumptions were made regarding:

i) the amount of energy that each plant would have produced;
ii) the future price of fuels;
iii) adjustments, if any, in the operation of the existing plants if new capacity is not introduced.

In the case of the nuclear plants E15 and E16, a capacity factor of 75% was assumed[8]. Ontario Hydro's fuel escalation factors were used to estimate future fuel costs[9].

It was assumed that there would be no adjustment in the operations at existing plants in the event that E15 and/or E16 are not built. Since these stations are intended to provide base load power, their elimination would mean that ways of reducing base load demand or finding alternative base load energy supplies would have to be found.

Regarding the future price of fuels, it is worth noting that the escalation factors that Ontario Hydro prepares for forecasting these future costs are developed in detail for a ten year period, after which a single value is projected for all succeeding years. In the case of both coal and uranium, the annual rate of escalation forecast for the eleventh year onward is less than the average rate of the first ten years. With respect to coal, this difference is not very great, but for uranium the annual escalation rate forecast from the eleventh year is less than half the average rate of the ten preceeding years.

In comparison with other long-range forecasts of fuel availability and price, the Ontario Hydro forecasts may, therefore, be on the optimistic side[10]. Consequently, by using Ontario Hydro's escalation factors, particularly in the period following the next decade, the savings obtained from curtailing the expansion program, estimated in this study, may well be too low.

One of the features of LRF 48A is especially significant to the estimate of the fuel costs saved by not building

the coal-fired plants E17 and E18. Over the duration of the program, the fossil plants become increasingly used for supplying peak load power rather than base load power, and for providing reserve capacity for the system. For this reason, Ontario Hydro does not expect the increase in coal-fired capacity resulting from the construction of E17 and E18 to increase the amount of coal used annually for generating electricity[11]. The 15.5 million tons of U.S. equivalent coal forecast for consumption in 1986 is equal to the projected annual average consumption for the succeeding eleven years. What is expected to change is the pattern of useage of this coal, as it is used increasingly to satisfy peak demand.

For the present study, an important implication of these plans is that the elimination of E17 and E18 will not result in any fuel savings, if it is assumed that the coal-fired stations existing in 1986 will continue to be operated, as they will be in 1986, throughout the time period that follows. On the assumption, therefore, that adjustments will be made in the operation of Ontario Hydro's coal-fired capacity in the absence of E17 and E18, the consumption of coal will not be affected by their elimination from the expansion program[12]. The only difference, an important one from a system planning point of view, is that if E17 and E18 are not built, Ontario Hydro will be less able to supply the peak demand that is projected. Therefore, the alternative energy measures must be able to compensate.

The assumptions described in this section underlie the fuel use forecasts and estimated savings to be obtained from eliminating stations E15, E16, E17 and E18, that are recorded in tables III.1 to III.5 in section 5.

5. ESTIMATED CAPITAL OPERATION, MAINTENANCE AND FUEL COST SAVINGS

The previous sections detailed the assumptions which were the basis for estimating cost savings resulting from eliminating plants from LRF 48A. This section outlines the estimates.

Tables III.2 to III.5 show the estimated savings that would be achieved by the elimination of stations E15 to E18 respectively. Table III.6 is a summary of the savings that would result from the successive elimination of these four stations.

All tables span the period 1980-2007. 1980 is the first year in which there would be any saving from the elimination of plants after Darlington G.S.: $4 m of capital costs for E15. 2007 is the last year for which Ontario Hydro has published a load forecast. On the assumption that all of the plants would have an operational life of 30 years or more[13], a decision not to build any or all of them would also bring savings beyond the year 2007, but these have not been estimated.

Tables III.2 - III.5 display the considerable costs of constructing and operating particular stations. The costs show a similar pattern for each station: capital costs begin from 5 to 7 years before any energy is forthcoming and from 8 to 10 years before the stations are fully in service. These capital costs rise to a peak and are in decline by the time the first unit is operating. As the units of each station come into service, operation and maintenance costs commence, as do fuel costs for the nuclear plants. (It has been assumed that the fuel costs for the fossil stations are matched by reductions in the fuel costs of other fossil plants and so no fuel costs have been attributed to E17 and E18.)

The same general pattern of costs appears in table III.6, which shows the combined costs of eliminating successive plants from Ontario Hydro's expansion program. The last column, for example, shows that the annual cost savings from eliminating all four plants rises from $4 million in 1980 to over $2 billion in 1987. They decline somewhat after that as the construction of all four stations is completed but rise again, at least in terms of current dollars, until the annual savings achieved by avoiding operation, maintenance and fuelling costs approaches the $1 billion level.

To avoid giving a misleading impression of exact figures, all of the dollar values in the tables are rounded to the

TABLE III.2

ESTIMATED ANNUAL CAPITAL, OPERATION, MAINTENANCE AND FUEL COSTS ASSOCIATED WITH E15 (4 X 516 mw CANDU), 1980 - 2007

YEAR	UNITS IN SERVICE[1]	ENERGY OUTPUT (GWH)[2]	CAPITAL COST (Current $m)[3]	OPERATION AND MAINTENANCE COST (Current $m)[4]	FUEL COST (Current $m)[5]	TOTAL COST (Current $m)
1980	0	0	4	0	0	4
1981	0	0	80	0	0	80
1982	0	0	154	0	0	154
1983	0	0	237	0	0	237
1984	0	0	373	0	0	373
1985	0	0	612	0	0	612
1986	0	0	669	0	0	669
1987	.5	1,695	542	6	4	552
1988	1.25	4,238	333	16	12	361
1989	3.25	11,018	72	44	40	156
1990	4.0	13,560	0	57	41	98
1991	4.0	13,560	0	61	43	104
1992	4.0	13,560	0	66	46	112
1993	4.0	13,560	0	70	48	118
1994	4.0	13,560	0	75	51	126
1995	4.0	13,560	0	80	54	134
1996	4.0	13,560	0	85	57	143
1997	4.0	13,560	0	91	60	151
1998	4.0	13,560	0	97	63	160
1999	4.0	13,560	0	104	67	171
2000	4.0	13,560	0	111	70	181
2001	4.0	13,560	0	119	74	193
2002	4.0	13,560	0	127	78	205
2003	4.0	13,560	0	135	83	218
2004	4.0	13,560	0	145	87	232
2005	4.0	13,560	0	154	92	246
2006	4.0	13,560	0	165	97	262
2007	4.0	13,560	0	176	102	278

1. LRF 48A
2. 75% capacity factor assumed
3. Ontario Hydro
4. Based on Fig. 2.1, 8-2 in Generation - Technical by Ontario Hydro (40)
5. Ontario Hydro

TABLE III.3

ESTIMATED ANNUAL CAPITAL, OPERATION, MAINTENANCE AND FUEL COSTS ASSOCIATED WITH E16 (4 x 850 mw CANDU), 1980 - 2007

YEAR	UNITS IN SERVICE[1]	ENERGY OUTPUT (GWH)[2]	CAPITAL COST (Current $m)[3]	OPERATION AND MAINTENANCE COST (Current $m)[4]	FUEL COST (Current $m)[5]	TOTAL COST (Current $m)
1980	0	0	0	0	0	0
1981	0	0	39	0	0	39
1982	0	0	151	0	0	151
1983	0	0	234	0	0	234
1984	0	0	381	0	0	381
1985	0	0	593	0	0	593
1986	0	0	902	0	0	902
1987	0	0	903	0	0	903
1988	0.5	2,792	720	6	8	734
1989	1.25	6,981	457	17	20	494
1990	3.25	18,150	91	48	55	194
1991	4.0	22,338	1	63	72	136
1992	4.0	22,338	0	67	76	143
1993	4.0	22,338	0	72	80	152
1994	4.0	22,338	0	77	84	161
1995	4.0	22,338	0	82	89	171
1996	4.0	22,338	0	88	94	182
1997	4.0	22,338	0	94	99	193
1998	4.0	22,338	0	100	104	204
1999	4.0	22,338	0	107	110	227
2000	4.0	22,338	0	114	116	230
2001	4.0	22,338	0	122	122	244
2002	4.0	22,338	0	130	129	259
2003	4.0	22,338	0	139	136	275
2004	4.0	22,338	0	149	144	293
2005	4.0	22,338	0	159	152	311
2006	4.0	22,338	0	170	160	330
2007	4.0	22,338	0	181	169	350

1. LRF 48A
2. 75% capacity factor assumed
3. Ontario Hydro
4. Based on Fig. 2.1, 8-2 in Generation - Technical by Ontario Hydro (40)
5. Ontario Hydro

TABLE III.4

ESTIMATED ANNUAL CAPITAL, OPERATION AND MAINTENANCE COSTS ASSOCIATED WITH E17 (4 x 750 mw COAL FIRED), 1980 - 2007[1]

YEAR	UNITS IN SERVICE[2]	CAPITAL COST (Current $m)[3]	OPERATION AND MAINTENTANCE COST (Current $m)[4]	TOTAL COST (Current $m)
1980	0	0	0	0
1981	0	0	0	0
1982	0	0	0	0
1983	0	27	0	27
1984	0	99	0	99
1985	0	145	0	145
1986	0	247	0	247
1987	0	386	0	386
1988	0	440	0	440
1989	1.25	307	12	319
1990	2.5	145	26	171
1991	3.75	25	41	66
1992	4.0	0	47	47
1993	4.0	0	50	50
1994	4.0	0	53	53
1995	4.0	0	57	57
1996	4.0	0	60	60
1997	4.0	0	64	64
1998	4.0	0	68	68
1999	4.0	0	73	73
2000	4.0	0	78	78
2001	4.0	0	82	82
2002	4.0	0	88	88
2003	4.0	0	94	94
2004	4.0	0	100	100
2005	4.0	0	107	107
2006	4.0	0	114	114
2007	4.0	0	121	121

1. Energy output and fuel costs are omitted since E17 is not expected to make a net contribution to the total energy supplied and coal consumed by Ontario Hydro's fossil plants. See text for a further explanation.

2. LRF 48A

3. Ontario Hydro

4. Based on Fig. 2.1, 8-2 in Generation - Technical by Ontario Hydro (40)

TABLE III.5

ESTIMATED ANNUAL CAPITAL, OPERATION AND MAINTENANCE COSTS ASSOCIATED WITH E18 (4 x 750 mw COAL FIRED), 1980 - 2007[1]

YEAR	UNITS IN SERVICE[2] 2	CAPITAL COST (Current $m)[3] 3	OPERATION AND MAINTENANCE COST (Current $m)[4] 4	TOTAL COST (Current $m)
1980	0	0	0	0
1981	0	0	0	0
1982	0	0	0	0
1983	0	0	0	0
1984	0	0	0	0
1985	0	51	0	51
1986	0	123	0	123
1987	0	178	0	178
1988	0	302	0	302
1989	0	451	0	451
1990	.25	454	3	457
1991	1.5	295	16	311
1992	2.75	121	32	153
1993	4.0	9	50	59
1994	4.0	0	53	53
1995	4.0	0	57	57
1996	4.0	0	60	60
1997	4.0	0	64	64
1998	4.0	0	68	68
1999	4.0	0	73	73
2000	4.0	0	78	78
2001	4.0	0	82	82
2002	4.0	0	88	88
2003	4.0	0	94	94
2004	4.0	0	100	100
2005	4.0	0	107	107
2006	4.0	0	116	114
2007	4.0	0	121	121

1. Energy output and fuel costs are omitted since E18 is not expected to make a net contribution to the total energy supplied and coal consumed by Ontario Hydro's fossil plants. See text for a further explanation.

2. LRF 48A

3. Ontario Hydro

4. Based on Fig. 2.1, 8-2 in <u>Generation - Technical</u> by Ontario Hydro (40)

TABLE III.6

ESTIMATED ANNUAL SAVINGS FROM ELIMINATING SUCCESSIVE PLANTS AFTER DARLINGTON G.S., 1980 - 2007[1]

YEAR	LRF 48A - E15	LRF 48A - (E15 + E16)	LRF 48A - (E15 + E16 + E17)	LRF 48A - (E15 + E16 + E17 + E18)
1980	4	4	4	4
1981	80	119	119	119
1982	154	305	305	305
1983	237	471	498	498
1984	373	754	853	853
1985	612	1,205	1,350	1,401
1986	669	1,571	1,818	1,941
1987	552	1,455	1,841	2,019
1988	361	1,095	1,535	1,837
1989	156	650	969	1,420
1990	98	292	463	920
1991	104	240	306	617
1992	112	255	302	455
1993	118	270	320	379
1994	126	287	340	393
1995	134	305	362	419
1996	143	325	385	445
1997	151	344	408	472
1998	160	364	432	500
1999	171	398	471	544
2000	181	411	489	567
2001	193	437	519	601
2002	205	464	552	640
2003	218	493	587	681
2004	232	525	625	725
2005	246	557	664	771
2006	262	592	706	820
2007	278	628	749	870

1. Summation of total costs from tables III.1 - III.4.

nearest million. Also the values are in current dollars rather than constant dollars primarily because most of the data obtained from Ontario Hydro were provided in current dollars. Ontario Hydro's forecasted escalation factors have been used to generate the current dollar figures wherever the data were not already supplied by Ontario Hydro in that form.

In the next chapters, the streams of costs recorded in table III.6 are used to determine the cost competitiveness of a variety of measures which, suitably combined, may be capable of replacing some of the proposed generating stations in LRF 48A without any loss in services to the people of Ontario.

FOOTNOTES:

1. Errata Sheet for Planning of the Ontario Hydro East System Report No. 5733P - Part 1, Ontario Hydro, 1976. (42)

2. Ontario Hydro, Submission to the Royal Commission on Electric Power Planning, Generation - Technical, Vol. 1., 1976 Figure 2-1, 8-2 (40)

3. Personal communication from a staff member of the Royal Commission.

4. In a personal communication an employee of Ontario Hydro stated that the estimates are for CANDU and coal-fired stations operating at an annual capacity factor of 20-80%.

5. Ontario Hydro Economic Forecasting Services, November 1976. (25)
   On the advice of Ontario Hydro, for nuclear stations these escalation factors were applied with weights of 88% for labour and 12% for materials, and for coal stations, weights of 70% for labour and 30% for materials were used.

6. Personal communication from Ontario Hydro.

7. Generation - Technical (40) p.2.1-79 gives a figure of $10.26 per mwh in $1975. This figure was raised by 2.46% to account for the increase in the price of the U.S. coal from 1975 to 1976, according to information provided by Ontario Hydro.

8. Personal communication from Ontario Hydro

9. Economic Forecasting Series, Ontario Hydro, November 1976. (25)

10. See, for example, Energy Global Prospects 1985-2000 C.L. Wilson (ed.), 1977 (59)

11. Personal communication from Ontario Hydro, 19/7/77,

12. To the extent that adjustments would not be made, implying quite reasonably that the existing coal-fired plants will only be used for peaking with or without E17 and E18, this assumption leads to an underestimate of the total fuel savings.

13. Ontario Hydro <u>Generation - Technical</u>, p.2.1 - 67 (40)

CHAPTER IV

A REVIEW OF ALTERNATIVES TO BUILDING LARGE GENERATING STATIONS IN ONTARIO

1. INTRODUCTION

This Chapter reviews the technical potential and economic cost of various measures which might be useful for reducing Ontario's dependence on a highly centralized and rapidly expanding electric generating system. The discussion is based entirely on the available literature, occasionally supplemented by reference to conversations with experts. Where there are significant disagreements in the literature as to technical potential and/or economic cost or where there are complete gaps in information, judgement has been exercised, generally in a conservative manner.

The measures considered may be divided into two categories: those which supply electricity from sources other than conventional power stations and those which reduce the demand for electricity.

<u>Supply Measures</u>

Industrial cogeneration
Electricity from biomass
Wind generated electricity
Electricity from small hydraulic sources
Interconnections

Demand Measures

Increased insulation of residential buildings
Improved efficiency of residential appliances
Energy savings in the commercial sector
Energy savings in the industrial sector
Solar space and water heating
District heating
Load management

In this chapter the measures are reviewed independently of one another. The task of combining them into a compatible set, capable of providing the same services as a varying number of displaced generating stations is the topic of the next chapter[1].

2. INDUSTRIAL COGENERATION

Technical Potential

Industrial cogeneration is the production of electricity simultaneously with the production of industrial process steam. A study by Leighton and Kidd prepared for the Royal Commission on Electric Power Planning[2] assessed the technical feasibility and economic costs of industrial cogeneration in Ontario. The study also postulated a target capacity for Ontario in 1985, at about one half of the potential capacity that will be theoretically available. Leighton and Kidd estimated the maximum steam demands in existing industrial plants, assumed an annual growth rate of 5% in steam demands, and combined there with assumed steam utilization factors to estimate a potential

cogeneration electrical capacity for 1985 of 2085 mw. This may be compared with the estimated cogeneration capacity in Ontario in 1977 of 500 mw[3].

In order to examine the implications of Leighton and Kidd's assumptions for the years beyond 1985, identical assumptions were used in the present study to estimate the potential cogeneration capacity for each year up to 2007. These estimates are shown in the last two columns of table IV.1. The table also shows the estimated maximum steam demand (MSD) in the three sub-categories identified by Leighton and Kidd, (MSD $>$ 500,000 lbs/hr; 500,000 lbs/hr >MSD< 100,000 lbs/hr; MSD $<$ 100,000 lbs/hr).

For the years of greatest relevance to this study, 1987-1993, the estimated total potential capacity from industrial by-product power increases from 2377 mw to 3445 mw. Leighton and Kidd cite a capacity factor of 80% for cogeneration facilities, recognizing that about one half of the plants would be net exporters to the Ontario Hydro grid, matched by the other half which would be net importers.

The following equations, which are a generalization of Leighton and Kidd's methodology, were used to generate the estimates of table IV.1.

$$MSD_o^i = MSD_r^i \, (1 + K) \tag{1}$$

$$MW_o = \sum_i \left(MSD_o^i \times U_o^i \times 60\right) \tag{2}$$

$$MW_t = MW_o + \sum_i \left(MSD_o^i \, (1.05^t - 1) \, (U_t^i \times 60)\right) \tag{3}$$

$(t \neq o)$

TABLE IV.1

POTENTIAL POWER FROM COGENERATION

YEAR	MSD > [1] 500,000 lbs/hr	MW	500,000 lbs/hr >MSD> 100,000 lbs/hr	MW	MSD< 100,000 lbs/hr	MW	TOTAL POWER: NEW POWER ONSTREAM (MW)	TOTAL POWER: CUMULATIVE FROM 1977 (MW)
1977 [2]	17.90	805	11.43	274	14.20	85		1164
1985 [3]	26.45	1318	16.89	519	20.98	248	921	2085
1986	27.77	1397	17.73	557	22.03	273	142	2287
1987	29.16	1481	18.62	597	23.13	299	150	2377
1988	30.62	1568	19.55	639	24.29	327	157	2534
1989	32.15	1660	20.52	683	25.50	356	165	2699
1990	33.75	1756	21.55	729	26.78	387	173	2872
1991	35.44	1857	22.63	778	28.12	419	182	3054
1992	37.21	1964	23.76	828	29.52	453	191	3245
1993	39.07	2075	24.94	882	31.00	488	203	3445
1994	41.03	2193	26.19	938	32.55	525	211	3656
1995	43.08	2316	27.50	997	34.17	564	221	3877
1996	45.23	2445	28.88	1059	35.88	605	232	4109
1997	47.49	2580	30.37	1124	37.68	648	243	4352
1998	49.87	2723	31.84	1192	29.56	694	257	4609
1999	52.36	2873	33.43	1264	41.54	741	269	4878
2000	54.98	3030	35.10	1339	43.62	791	282	5160
2001	57.73	3195	36.85	1418	45.80	843	296	5456
2002	60.62	3368	38.70	1501	48.09	898	311	5767
2003	63.65	3550	40.63	1588	50.49	956	327	6094
2004	66.83	3741	42.66	1679	53.02	1017	343	6437
2005	70.17	3941	44.79	1775	55.67	1080	359	6796
2006	73.68	4152	47.03	1876	58.45	1147	379	7175
2007	77.36	4373	49.38	1987	61.37	1217	397	7572

1. MSD = maximum steam demand (lbs/hr)

2. Potential for 1977 estimated by Leighton & Kidd (about 40% of the estimated theoretical maximum) (22)

3. Target potential estimated by Leighton & Kidd (about 48% of the estimated theoretical maximum) (22)

where:

MSD_r^i = maximum steam demands reported via a questionnair category i

($i = 1; MSD^1 > 500{,}000$ lbs/hr
$i = 2; 500{,}000 \text{ lbs/hr} > MSD^2 > 100{,}000$ lbs/hr
$i = 3; 100{,}000 \text{ lbs/hr} > MSD^3$)

MSD_o^i = estimated maximum steam demands in the base year (1977)

MW_o = potential electrical capacity of cogeneration in the base year

U_t^i = assumed steam utilization factor for category i in the yeat t. i.e. % of steam demand utilized for cogeneration

Equation (1) states that the potential electrical capacity in 1977 in category i of maximum steam demands is equal to the reported maximum steam demand plus a prorated portion (K) of the estimated steam demands of plants for which no completed questionnaire was received.

Equation (2) states that the potential electrical capacity in 1977 is equal to the estimated maximum steam demand in each category multiplied by an assumed potential steam utilization factor in each category multiplied by an assumed installed capacity of 60 kw per 1000/lbs/hr of maximum steam demand.

Equation (3) states that the potential electrical capacity in any year after 1977 is equal to the potential electrical capacity for 1977 plus the estimated maximum steam demand for that year (assumed to grow at 5% per annum from 1977 onwards) multiplied by the assumed utilization factor for the year, multiplied by the assumed installed capacity of 60 kw per 1000 lbs/hr of maximum

steam demand. Table IV.2 shows the steam utilization factors assumed for the purpose of these estimates.

TABLE IV.2

ASSUMED STEAM UTILIZATION FACTORS

YEAR		MSD > 500,000 lbs/hr	500,000 lbs/hr > MSD > 100,000 lbs/hr	MSD < 100,000 lbs/hr
1977	(U_o^i)	75%	40%	10%
1978 and beyond	(U_t^i)	100%	75%	40%

Source: Leighton and Kidd, Industrial By-Product Power (22)

In assessing the accuracy of the estimates shown in table IV.1, a number of considerations are relevant.

i) On a pro-rata basis, Leighton and Kidd calculated that the 62 plants for which no report was received account for a maximum steam demand of 11,380,000 lbs/hr[4]. Only one half of this amount was actually used in estimating the maximum steam demands in 1977.

ii) The assumed utilization rates for existing and future plants shown in table IV.2 imply an estimated potential for by-product power that is less than 45% of the theoretical potential in 1977, rising to 50% in 1985, and reaching 62% by 1995. This suggests a generous margin to allow for situations where the generation of by-product power is impractical.

iii) The assumed 5% annual growth rate of steam demands must be interpreted as the growth net of decommissioning old plants. Growth in industrial steam demands is likely to be biased toward larger plants for which a greater utilization rate has been assumed. However, this factor, which would tend to increase the potential for by-product power, has been omitted from the projection since it has been assumed that each of the three categories of steam demands will grow at the same annual rate.

In view of these considerations, the estimated potential for by-product power shown in table IV.1 may be regarded as reasonable and not particularly optimistic. Moreover, as will become clear in the next chapter, the rate of implementation of cogeneration assumed by Leighton and Kidd between 1977 and 1985 is much faster than is required to achieve the goals of the present study, i.e. to provide substitutes for Ontario Hydro's proposed expansion after Darlington G.S. In the next chapter a cogeneration implementation program is developed that is consistent with the estimates of potential capacity developed in this chapter, and brings the capacity on-stream during the first part of the 1980s so that it is in place by 1987.

Economic Costs

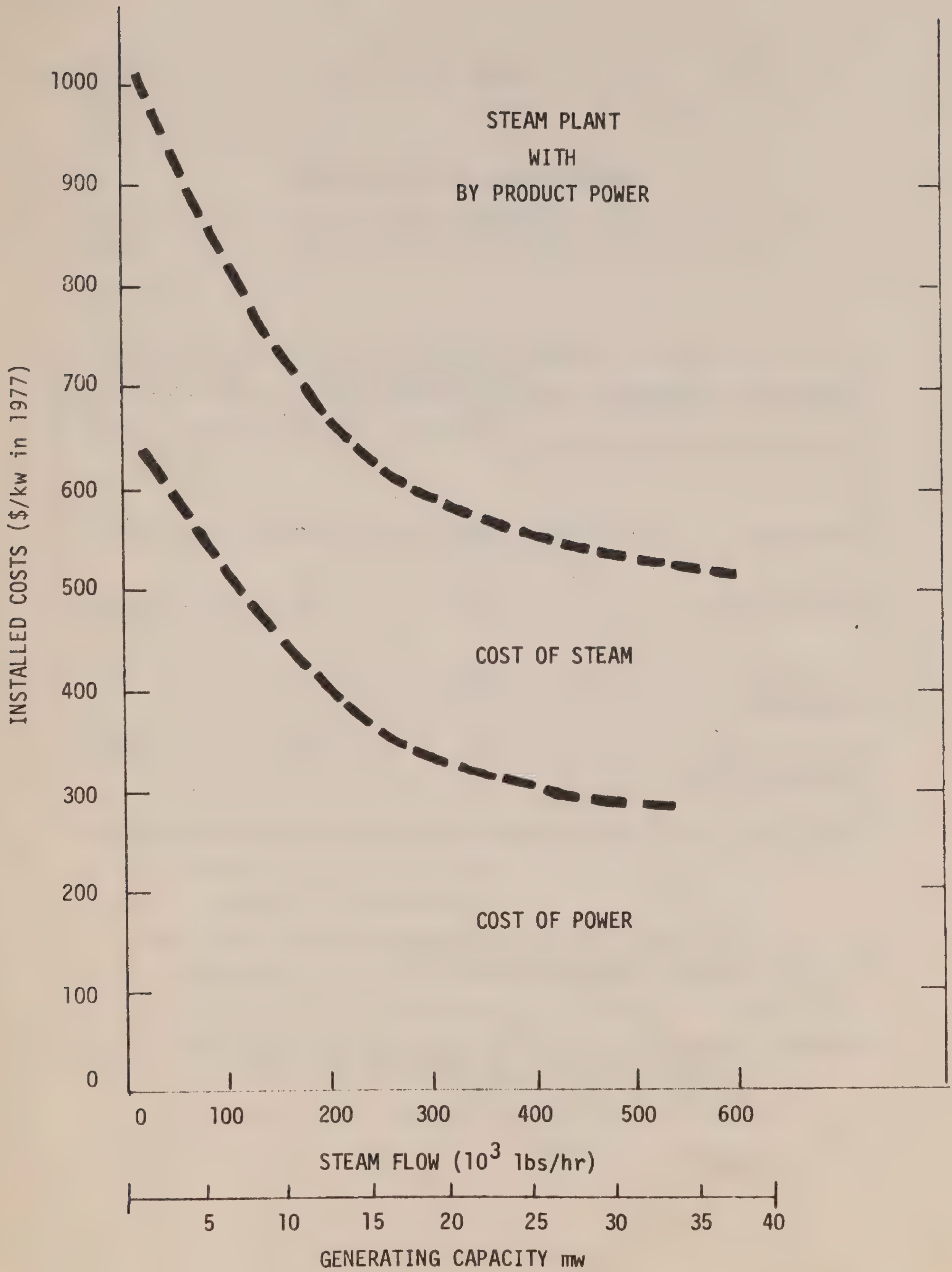
Leighton and Kidd have estimated the costs of industrial cogeneration[5]. Figure IV.1 shows the estimates of the capital costs of new steam plants installed with turbine generation. Costs included are for construction, equipment, engineering, administration and interest. The upper curve shows the costs incurred if steam is raised only for process heat without any provision for by-product power. The lower curve shows the incremental costs incurred for cogeneration.

In the case of retrofitting existing steam plants, much depends on the degree of adjustment that must be made to the steam facilities. Some plants, in which provision has been made for retrofitting, will have costs lower than the lower curve in figure IV.1. Costs will be much higher than this, possibly as high as the upper curve, if the steam plant must be replaced prematurely.

Estimates of cogeneration captial costs in four categories of expenditure are shown in table IV.3. The first two categories, new plant and existing plant, are self explanatory and correspond exactly to Leighton and Kidd's classification. The third category refers to a new plant whichis installed and for which expenditures can be incurred in preparation for retrofitting electrical generation facilities at some future date. These costs are assumed to be 15% of the costs of the new plant[6]. The estimated cost of retrofitting this prepared

FIGURE IV.1

ESTIMATED COSTS OF COGENERATION



Source: Leighton and Kidd, <u>Report on Industrial By-Product Power</u> (22)

TABLE IV.3

CAPITAL COSTS FOR COGENERATION

($/kw in 1977)

Expenditure Category	SIZE OF STEAM PLANT[1] (MSD lbs/hr)		
	500,000	300,000	50,000
New Plant	300	340	600
Existing Plant	540	600	920
Preparing New Plant	45	51	90
Retrofitting Prepared Plant	255	289	510

1. These sizes are taken as representative of the three categories identified earlier.

SOURCE: Figure IV.1. N.B. this figure is for 1976 conditions. No specific adjustment has been made for table IV.3 to correct the data to 1977 dollars.

capacity is the fourth category of expenditure and is equal to the estimated costs for a new plant given in the first row, minus the costs incurred for preparing for retrofitting.

The operation, maintenance and fuel costs, plus Ontario Hydro's standby charge, given by Leighton and Kidd and used here, are shown in table IV.4.

The data in tables IV.3 and IV.4 are used as the basis for estimating the costs of implementing the cogeneration plan that is developed in the next chapter.

3. THE GENERATION OF ELECTRICITY FROM BIOMASS

Technical Potential

There are two major sources of biomass in Ontario that could be used as fuel for generating electricity: forest industry wastes, and municipal sold wastes. In addition, there is the possibility of using dedicated forest and agricultural biomass and agricultural wastes. The available information about each of these sources is very inadequate and the estimates described in this section should be interpreted accordingly.

It is recognized that there are several potential competitors for the use of biomass. The production of methanol as a supplement to, or replacement for, gasoline is the major one. Consequently, although it might be technically feasible to use all of the collectable biomass for generating electricity, it would be unreasonable to base the estimates of technical potential

TABLE IV.4

OPERATION, MAINTENANCE, FUEL AND OTHER COSTS FOR COGENERATION 1 KW OF INSTALLED CAPACITY

(1977 Dollars)

Operation and Maintenance	$15.00
Ontario Hydro Standby Charge	6.96
Fuel[1]	49.41
Total	$71.37

1. Leighton & Kidd use $1.50 per Btu for fuel costs, and 4700 Btu/kwh as the additional heat requirements for by-product electricity. The fuel cost figure in the table assumes an 80% capacity factor.

SOURCE: Leighton & Kidd, p.18 (23)

on such an assumption. In the present study, therefore, it is assumed that only a minor portion of the collectable biomass, estimated for the years 1976 and 1985, is available for electricity generation.

Table IV.5 shows tentative estimates of the biomass available from various sources, the percentage assumed to be collected and the percentage assumed to be diverted to other uses. It also shows estimated conversion factors in terms of kwh/ton of biomass, and the electrical energy that could have been generated in 1976 and could be generated in 1985: 5.34×10^9 kwh and 8.86×10^9 kwh, respectively. Assuming a capacity factor of 70%, these levels of energy output correspond to capacity requirements of 870 mw and 1445 mw.

One issue that is not made explicit in table IV.5 is whether the estimated biomass available for electricity generation in 1985 would be burned in existing or planned facilities, or in new plants specifically designed for using this type of fuel. If it is assumed that some of the biomass would be used to replace fossil fuels in facilities that will be in place in 1985, the <u>net</u> contribution that electricity generated from biomass can make might be reduced to an equivalent of 1000 mw.

In addition to the biomass sources for which estimates are given in table IV.5, fuel could also be obtained from dedicated forest and agricultural biomass and possibly from agricultural wastes. One report has suggested that by 1985, 25 million oven dried tons per year of dedicated forest biomass could be available in Ontario[(7)]. If only 25% of this quantity were to be used for generating electricity it would produce approximately 10×10^6 mwh/yr, which

TABLE IV.5

ESTIMATES OF ELECTRICAL ENERGY AND CAPACITY FROM THE USE OF BIOMASS FUEL

BIOMASS SOURCE	QUANTITY PRODUCED (10^3 odt*/yr) 1976	QUANTITY PRODUCED (10^3 odt*/yr) 1985	% ASSUMED COLLECTED[2]	AMOUNT AVAILABLE (10^3 odt/yr) 1976	AMOUNT AVAILABLE (10^3 odt/yr) 1985	PERCENT DIVERTED TO OTHER FORMS	CONVERSION FACTORS (kwh/ton) (@ 10500 Btu/kwh)	ELECTRIC ENERGY AVAILABLE (10^9 kwh/yr) 1976	ELECTRIC ENERGY AVAILABLE (10^9 kwh/yr) 1985
FOREST BIOMASS									
- mill residues	748[1]	1197	90	673	1077	assume 60% diverted to pulp, steam or methanol production	1600[7]	.43	.69
- forest wastes (slash)	5084[1]	8134[3]	60	3050	4880		1600[7]	1.95	3.12
- unused trees	3415[1]	5464[3]	60	2049	3278		1600[7]	1.31	2.10
SOLID WASTE	6000[4]	7800[5]	63[6]	3780	4914	assume 50% diverted to steam (district heating etc.)	875[8]	1.65	2.15
				TOTAL ENERGY (10^9 kwh/yr)				5.34	8.86
				TOTAL POWER ASSUMING 70% CAP. FACTOR (mw)				870	1445

*odt = Oven Dry Tons. Solid waste figures are 'as received'.

1. Hall, R.J., Resource Availability and Utilization of Forests for Energy, 1976, p. 11 Table 3
2. Assumed constant 1976 to 1985 (15)
3. Methanol in Ontario Preliminary Report, Dept. of Chemical Engineering and Applied Chemistry, University of Toronto, 1976. p. 37 (8) estimates 1985 quantities as 1.6 times 1976 values.
4. Williamson, W., Ontario Centre for Resource Recovery: Experimental Plant, Ministry of Environment, 1977 p. 5. note - these are not odt they are as-collected (wet) (58)
5. Payne and McColgan, Energy from Refuse, the Potential in Canada, 1974, Table IV (45)
6. Percent of Ontario's population living in cities of 250,000 or larger, 1976 census
7. "Energy from Forest Biomass" report for Long Term Energy Assessment Program, Dept. of E.M.R., Ottawa, April 77 Appendix C (11)

corresponds, at a 70% capacity factor, to 1630 mw of generating capacity. It does not seem unrealistic, therefore, to assume that in 1985 and the years following, there will be sufficient biomass available in Ontario to provide fuel for at least an additional 750 mw of generating capacity.

Economic Cost

Several studies cite estimates for the costs of generating electricity from biomass. These estimates are summarized in Table IV.6.

TABLE IV.6

A SUMMARY OF ESTIMATES OF CAPITAL COSTS FOR GENERATING ELECTRICITY FROM BIOMASS

STUDY	CAPACITY mw	CAPITAL COST ($m)	YEAR	$/kw
SNC	25	20	1976	800
BATTELLE	50	42.5	1980	850
J.P.R.	150	126	1978	840
MITRE	112	75	1976	670

Sources: See J.P.R. Associates, The Feasibility of Generating Electricity in the State of Vermont, August, 1975 (20) SNC Consultants Ltd., Hearst Wood Wastes Energy Study, 1976 (52) Mitre Corporation, Conference on Silviculture Biomass Plantations, 1977 pp. 6-99 (26) Batelle Columbus Labs., Comparison of Fossil and Wood Fuels , 1976(3)

Allowing for the differences in the value of the dollar (U.S. and Canadian) at the various dates, there seems to be general agreement about the capital cost of generating electricity from biomass. The J.P.R. study stresses the significance of economies of scale and selects a 150 mw plant as the largest that could be built given the maximum size for which wood burning boilers are presently available. Since one or more plants of this scale are small enough not to be considered large scale generating stations, 150 mw was selected in the present study as the size of biomass-fuelled facilities for comparison with the much larger stations proposed by Ontario Hydro.

The capital cost of such a 150 mw plant was taken to be $180m (1985). This figure which amounts to $1200/kw is somewhat less than the cost per kw derived by increasing the J.P.R. estimate by Ontario Hydro's escalation factors for the construction of coal fired plants. However, it does correspond to the estimate given by Ontario Hydro for a 150 mw coal fired plant[8] and the J.P.R. study states that a wood fired plant of this size should cost about the same as one fuelled by coal[9].

Estimates for the costs of operation, maintenance and fuel are shown in table IV.7.

The wide divergence among these costs requires some explanation. The very low fuel costs for the Hearst plant (SNC study) are due to the fact that wastes from local mill operations would be used and only very modest transportation and ash disposal costs would be involved. The relatively high operation and maintenance costs of the Hearst plant can be attributed in large part to the small scale of the plant.

TABLE IV.7

ESTIMATES FOR OPERATION, MAINTENANCE AND FUEL COSTS FOR THE GENERATION OF ELECTRICITY FROM BIOMASS

STUDY	CAPACITY mw	OPERATION AND MAINTENANCE COSTS ($000)	($/kw)	FUEL COSTS mills/kwh	YEAR
BATTELLE (3)	50	710	14.2	19.9	1980
SNC (49)	25	1,105	44.2	1.7	1976
J.P.R.	150	2,190	14.6	17.9	1978
MITRE (25)	112	4,704	42	no estimate	1976

According to the J.P.R. study, the operation and maintenance costs for a wood plant would be less than for an equivalent sized coal plant but higher than for an oil plant. On this basis, operation and maintenance costs in 1985 dollars are taken, in this study, to be \$20/kw[10], a figure which is consistent with the estimates made by Battelle and J.P.R.

The most difficult cost component to estimate is that of fuel. Both the Battelle and J.P.R. studies assume that wood will have to be purchased at considerable expense[11]. This contrasts with the SNC study which estimates that only modest transportation costs are involved. The previous section indicated that in 1985 there will be sufficient biomass from wastes of different kinds in Ontario to support a net addition to capacity of at least 750 mw. The costs of fuelling this amount of capacity will depend on the extent to which the various forms of biomass are utilized. This is because, as table IV.8 shows, the estimated cost per ton of each type of biomass varies significantly. A ton of solid waste has a negative cost of \$7 (1974 dollars), owing to the savings in disposal costs if solid waste is used as fuel. The cost of a ton of forest biomass, in each of the forms considered, is much higher, reflecting the expected competition from other possible uses of these resources.

To arrive at an estimated fuel cost figure two approaches are taken:

i) the least costly combination of fuel costs, using solid waste, mill residues and some forest wastes;

TABLE IV.8

ESTIMATED FUEL COSTS FOR ELECTRICITY

GENERATED FROM BIOMASS

BIOMASS SOURCE	COST/TON IN 1974	COST/TON IN 1985[4]
Mill Residues[1]	\$20 (ODT)	\$38
Forest Wastes (slash)[2]	\$27.5 (ODT)	\$52
Unused Trees[1]	\$35.0 (ODT)	\$66
Solid Waste[3]	-\$ 7.0 (as received)	-\$13

1. P.P.R.I. of Canada, Feasibility Study of Production of Chemical Feedstock from Wood Waste (47)

2. Assumed average of the costs of mill residues and unused trees.

3. Report of the Solid Waste Task Force to the Ontario Minister of the Environment, 1974, Vol. I, (48)

4. 1974 figures escalated at 6% per year.

ii) a fuel cost representing a weighted average of the four biomass sources.

These two approaches give the following estimated fuel costs for 1985:

- least costly combination = $.01/kwh
- weighted average = $.02/kwh

In the cost comparison between electricity generated from biomass and coal discussed in Chapter V, a fuel cost of $0.03/kwh is used for biomass to allow for a considerable margin of error in the cost estimates.

4. WIND GENERATED ELECTRICITY

Technical Potential

The most promising use of wind power to generate electricity is in remote areas of the province with modest power requirements that must otherwise be met by the use of fossil-fuelled generators(12). However, for the purpose of this study, it is necessary to consider the possibility of a large scale application of wind power, sufficient to displace at least one unit of a 4 x 516 mw generating station. Bearing in mind the rapid rate of development in windmill technology, it is reasonable to assess the potential for wind power in Ontario in terms of use of wind plants of 1 mw capacity(13).

Assuming that the average capacity factor of windmills is 35%[13] i.e. that one may expect 350 avg. kw/yr from 1 mw windmill and that a 516 mw unit produces approximately 390 avg. mw/yr,one would need in the order of 1100 mills of 1 mw each to equal 1 x 516 per unit. This assumes that each mill would operate independently of its neighbours and that arrary effects of loading and shielding would not be present.

Regarding the land requirements, it is assumed that the mills would be built in groups or arrays of at least 10 at any location. A typical 1 mw mill, 150' in diameter, is designed to operate at a mean speed of 18 mph. At a very conservative estimate of 30 windmill diameters per mill spacing[14] to assure independent operation, an area of 800 square miles, or approximately .7 square miles per mill would be required.

In a province as large as Ontario it may not seem difficult to envisage an area equivalent to a square the sides of which measure 28 miles, especially when it is recognised that to use the land for wind generated electricity may still allow it to be used for some other purposes. The problem lies in finding such an area with an average wind speed of 18 mph or greater.

One study[15] indicated that areas of high wind speed in Ontario are almost entirely around Hudson Bay, and there the average wind speed is only 12.5 - 15 mph. Only three measuring stations reported winds in excess of 15 mph. Assuming other factors are constant, the power in 12.5 mph winds compared to 18 mph winds may be approximated by the

ratio$\left(\frac{12.5}{18}\right)^3$ = .34, or the equivalent of almost 3250 mills required to produce as much power as a 516 mw nuclear unit. These mills would require roughly 2,300 square miles of land though not all in one location

Economic Cost

The cost of windmills having a 1 mw capacity is expected to be in the order of $500/kw (1976)[16] for modest production runs. Using the estimated 3,250 mills necessary to displace a single 516 mw nuclear unit, the capital cost would be approximately $1.6 billion. Although fuel costs are zero and operation and maintenance costs are not likely to be very significant, capital costs of this magnitude make the large scale application of wind generated electricity a very expensive option for Ontario.

5. ELECTRICITY FROM SMALL HYDRO-ELECTRIC SOURCES

Technical Potential

The largest source of unutilized hydraulic power in Ontario is the Albany River. A series of dams along the river would be capable of providing about 3,000 mw peak power and 2,000 average mw of energy[17] by 1990. This indicates a capacity factor of 70%, comparable to that of fossil or nuclear generation.

The Ontario Government has allowed Ontario Hydro to proceed with in-house studies to evaluate the utilization of the Albany River and to compare it with other power generation options [18]. However, given the objectives of the present study, the large scale exploitation of the Albany River is not considered to be an acceptable alternative to the generating stations that are planned for completion after Darlington G.S.

Ontario Hydro has estimated the energy available from undeveloped sites with a potential capacity larger than 10 mw to be 700 average mw or approximately 1700 mw peak capacity (dependable) [19]. In addition, there are 600 average mw available from the Severn River [20]. There are also 1000 or so smaller sites throughout the province, many of which were developed and subsequently removed from service owing to high costs. They have a capacity of about 790 average mw [3].

Economic Cost

Although no detailed cost estimates have been made for the development of these sites, Ontario Hydro notes that "there are a number of locations with a capacity greater than 10 mw annual energy which may be economic in comparison to fossil generation when additional capacity is required to meet system demands" [21]. For the purposes of the present study it is assumed that 10% of the available capacity in this category, i.e. 70 mw in total, can be brought on stream over the next 15 years at costs competitive with the fossil fuelled alternatives.

6. INTERCONNECTIONS

Technical Potential

Ontario Hydro has pointed out several ways by which increased interconnections with other utilities offer opportunities for improving system operation and potentially reducing the required system capacity[22]. Whenever there are differences in system load patterns, there may be a means of relying on the other system for peak power. For example, Ontario Hydro could exchange its extra summer capacity for winter capacity available from other utilities. A second method is to take advantage of variations in daily load peaking times.

However, Ontario Hydro thinks there are severe limitations in implementing either of these strategies. In a trial exchange experiment a few years ago, Michigan had unexpectedly low winter reserves. Systems at greater distance than Michigan could be unreliable because of transmission limitations, possible U.S. energy export restrictions and the "first call" priority which is the right of the intervening utilities transmitting the power. Also, daily load differences will be more limited when load management more successfully flattens the daily patterns.

The three major sources of interchange power for Ontario Hydro are Hydro Quebec, Manitoba Hydro and the U.S. utilities. Connection with Quebec is limited to 1300 to 1500 mw and is expected to decrease in the future if no new transmission facilities are constructed. 200 mw of

firm power are obtained from Manitoba (this contract lasts until 1982). Another 1500 to 3000 mw are technically available from Michigan and New York utilities, but power has been exported recently rather than imported[22].

In total, these represent between 3000 and 4700 mw of available capacity. Yet Hydro believes it cannot avail itself of the advantages of more interconnections because these adjacent utilities may not have sufficient reserve capacity in the next five to ten years to make sharing feasible. As well, a U.S. emergency could restrict export to Canada. Nevertheless, studies are underway to determine how to benefit more from interconnections.

The Select Committee of the Legislature looked at the question of interconnections and reserve capacity in 1976[23]. In their discussion they identify two important considerations. At present, Hydro's loss of load probability calculations do not take into account the potential for interconnection reserve. However, one study by Ontario Hydro did conclude that two large identical utilities similar to the present system could maintain present loss of load probabilities yet reduce reserve capacity between 750 mw and 1427 mw simply by having sufficient interconnections. The Select Committee therefore concluded that with Hydro's present interconnections, a lowering of reserve capacity by at least 500 mw and perhaps more than 1000 mw is warranted.

However, the issue of the costs and benefits of varying levels of reserve capacity is complicated[24] and it is presently receiving considerable attention in Ontario Hydro. Until more information is available it would be premature for the present study to presume the correctness of the Select Committee's recommendation. Consequently, the implications of recognizing the contribution of interconnections in relation to Ontario Hydro's capacity will be given a low priority in the next chapter.

Economic Cost

If the Select Committee recommendation is followed it amounts to a costless means of reducing Ontario Hydro's capacity, since it merely attributes a value to the existing pattern of interconnections. In other words, if the Select Committee is correct, Ontario Hydro can reduce its rate of capacity expansion and still maintain an acceptable level of reserve capacity.

7. INCREASED INSULATION OF RESIDENTIAL BUILDINGS

Technical Potential

Two categories of buildings need to be clearly identified: those that have already been built and those which are expected to be built during the next 30 years.

i) <u>The Existing Housing Stock</u>

The most recent year for which housing stock data of electrical use are available for Ontario is 1974.

TABLE IV.9

ELECTRICALLY HEATED HOMES IN ONTARIO 1974

TYPE OF ACCOMMODATION	NUMBER OF UNITS	ENERGY USE FOR HEATING kwh	PEAK REQUIREMENTS kw	ENERGY USE FOR HEATING 10^6 Btu
Single Family	113,000	22,700	6.44	77.5
Apartment	99,000	8,300	2.38	28.3
TOTAL	212,000	-	-	-

Source: Ontario Hydro Memorandum to the Board of Directors, 1976 (32)

The figures in column 4 of table IV.9 may be compared with those for all Ontario homes built after 1950[25]:

single family.....95 x 10^6 Btu

apartment.........24 x 10^6 Btu

The figure for single family homes includes heating requirements for homes heated by fossil fuels as well as electricity and is likely to be substantially higher than the heating requirements for electrically heated homes alone. Heating requirements for apartments heated with fossil fuels and electricity are low in comparison with single family homes.

The Scanada study considers that 36% saving in energy can be achieved by increasing the insulation in residential buildings of all types in Ontario[26]. The study also states that for Canada, dwellings built to the 1975 insulation standards require 9-16% less heat than units built in the previous 10 years. Assuming that electrically heated homes in Ontario approach this 1975 standard, the potential for savings can reasonably be estimated to be 23%. Applying this figure to the 77.5 x 10^6 Btu, derived from Ontario Hydro's figures for average demand yields 60 x 10^6 Btu, the average value which resulted from Scanada's estimates of the reduced energy requirements for all Ontario single family dwellings.

For existing apartment units, the average energy requirement is already quite low and further reduction is limited. The Scanada study suggests that little re-insulation is possible, but by restricting the rate of air change, an 18% saving may be achieved. Ontario Hydro uses 15% as the potential reduction in its study[27] and this is the magnitude of potential savings considered reasonable for the present study.

ii) <u>New Housing Stock</u>

Based on a 7300 degree day heating season[28], a study by HUDAC indicates that the 60 x 10^6 Btu per year figure cited above

corresponds approximately to the average heating requirements of a 1080 sq. ft. semi-detached house and a similarly sized row house, each meeting the 1975 residential insulation standards[29]. The study also shows that further insulation and re-design would reduce the energy requirement to 41.7×10^6 Btu and 33.1×10^6 Btu respectively (for 7300 DD). For the average dwelling, which is somewhat larger[30], this reduced demand might be about 46.5×10^6 Btu or 60% of the demand calculated earlier from the Ontario Hydro data. This level could be achieved in a house with sufficient insulation in the ceiling and exterior walls to allow heat loss coefficients of U = .032 and .062 respectively. Additional requirements could include double or triple glazing, 37% less fenestration and 35% reduced ventilation[31].

For apartment buildings Ontario Hydro estimates that not only is a 15% load reduction possible for improved insulation, but another 50% of the load can be reduced by improving the design and efficiency of the heating system. Consequently it is reasonable to assume that possible savings for heating over present levels in new apartment units would be 30%.

Table IV.10 displays the assumptions concerning the potential gains from improved insulation that have been outlined above. The values in table IV.10 are used in the next chapter in conjunction with the load forecasts of Chapter II, to estimate the effect of increased levels of residential insulation on Ontario Hydro's expansion program.

TABLE IV.10

ESTIMATES OF THE EFFECT OF INCREASED INSULATION ON ELECTRICAL HEATING DEMAND

DWELLING TYPE (electrically heated)	PRESENT ANNUAL REQUIREMENT (10^6 Btu)	IMPROVED INSULATION: EXISTING UNITS		IMPROVED INSULATION: NEW UNITS	
		% SAVING	ANNUAL REQ (10^6 Btu)	% SAVING	ANNUAL REQ (10^6 Btu)
Single family	77.5	23%	60	40%	46.5
Apartment	28.3	15%	24	30%	19.8

Economic Costs

From the Scanada report[31] the average investment to retrofit single family, row and duplex homes built after 1950 is $950 (1976 dollars). This investment results in homes that require an average estimated 60.3×10^6 Btus per year for space heating. Since electrically heated homes are already above the standard of insulation of the average post-1950 house, the actual cost of retrofitting them should be somewhat less to achieve the same final heating demand. Exactly how much less is unclear given the nature of diminishing returns in insulation investment. As a conservative figure, therefore, the same cost, $950, to retrofit an electrically heated home to the level suggested is assumed.

For apartments, the report suggests that $75 per unit could reduce heating demands by 18%. This cost figure and a more conservative reduction of 15% are used in the present study.

It has been estimated that a reduction in the annual heating requirements of a new home equivalent to 50% of the requirements of a typical fossil fuel heated home, can be obtained for $3,300, including $1,200 for a heat pump. Excluding the heat pump, it may be assumed that 40% of the heating requirements of an electrically heated home can be saved at a cost of between $2,000 - $2,500 for additional insulation. It should be noted that this saving of 40% in an electrically heated home represents a significantly smaller energy saving than the 50% reduction suggested above for a fossil fuel heated home. Consequently, the assumed cost figures reflect

diminishing returns in energy savings from increased expenditures on insulation.

The type and extent of improvement possible in new apartments is quite different from new houses. Not only is increased insulation and glazing recommended but also some adjustment to the total heating system. Since the total improvement expected for new buildings is only 30%, and 18% of this total can be obtained for $75 per unit for retrofit, a cost of $300 (1976 dollars) per unit is assumed for improvements to a new building.

TABLE IV.11

ESTIMATED PER UNIT COST FOR REDUCING HEATING DEMAND (1976 DOLLARS)

	RETROFIT	NEW
Single family	$950	$2250
Apartment	$ 75	$ 300

8. IMPROVED EFFICIENCY OF RESIDENTIAL APPLIANCES

Technical Potential

Excluding the use for space heating purposes, residential appliances accounted for more than 4600 mw, 34% of the system peak and about 20,000,000 mwh of electricity consumption (25% of the system requirements) in 1974. The details of end use consumption are shown in table IV.12.

In this section, the individual savings possible for each end use are estimated and subsequently applied to the load forecast to calculate total potential electricity savings. These savings are then transformed to peak reductions by adjusting them with the load factor for each end use. The load factors used are those derived from 1974 estimates. It is assumed that these annual load factors are constant over time for each end use.

Table IV.12 shows energy, power and load factors in 1974.

There have been several studies on the potential energy savings that can be derived from improvements in equipment efficiency. Two of these relate specifically to Ontario, while three others considered here are concerned with utilities in the United States[33].

The studies recommend a variety of means by which the efficiency of appliances can be improved. Some of these are:

TABLE IV.12

RESIDENTIAL ENERGY -

POWER AND LOAD FACTORS, 1974

END USE	TOTAL ENERGY USE 1974 (10^6 kwh)	ESTIMATED DEMAND COINCIDENT WITH PEAK 1974 (mw)	LOAD FACTOR
Electrical Space Heating	3,392	970	.40
Other Space Heating	1,405	345	.46
Water Heating	7,090	1,015	.80
Cooking	2,539	920	.32
Lighting	1,840	920	.23
Clothes Drying	1,040	500	.24
Refrigerator	3,295	370	1.02
Television	1,250	330	.43
Air Conditioning	251	-	-
Other	2,709	380	.81
TOTAL	23,770	5,750	Aug. .47

Source: Ontario Hydro <u>Memorandum to the Board of Directors</u>, October 12, 1976, Schedule "C" tables 2 and 4 (32)

i. <u>Water Heating</u>

- using a peak controller it is possible to shift <u>all</u> of a water heater's demand off-peak

- with improved design of water heaters and better insulation, savings estimated range upward from 10%

ii. <u>Ranges</u>

- the insulation on ovens can be increased with about a 50% reduction in heat loss

- microwave ovens are quoted as being 2 to 4 times more efficient than present stoves

iii. <u>Lighting</u>

- substituting fluorescent lights for incandescent would require only 25% of the present energy used

- in apartment buildings individual metering has a tendency to reduce consumption for lighting

iv. <u>Clothes Dryers</u>

- general improvements in efficiency from motors and heating

v. Refrigeration

- improved insulation in doors
- elimination of door heaters
- improved design efficiency of compressors

vi. Television

- further replacement of tubes with solid state; elimination of instant-on feature
- conversion to DC power for more efficient operation

vii. Air Conditioning

- higher insulation standards to reduce air conditioning requirements
- improved design of equipment

The present use and expected savings possible from these and other changes are listed in table IV.13. The final columns represent an average of the figures available (with exceptions noted).

The peak reductions can now be estimated. Table IV.14 shows that if the savings indicated in table IV.13 had been achieved in 1974, a 1000 mw reduction would have been possible.

TABLE IV.13

ESTIMATED SAVINGS FROM INCREASING THE EFFICIENCY OF RESIDENTIAL APPLIANCES (PER CENT)

	WATER HEATING	RANGES	LIGHTING	DRYERS	REFRIG-ERATION	TELEVISION	AIR CON-DITIONING
ONTARIO HYDRO (33) (Ontario)							
Present Use (kwh/yr)	5400 (1)	1200	750 (2)		900-1000	350-550	600
Savings, 1981	10%	50%	10-50%	-			
ENERGY PROBE (12) (Ontario)							
Present Use (kwh/yr)	5562	1221	750	900	1338	400	750
Savings, 1995	20%	30%	32.5%	15%	30%	50%	25%
GOLDSTERN/ROSENFELD (14) (California)							
Present Use (kwh/yr)			697		1400	42%-	2400-3600
Savings (max.)	100% (5)	100% (5)	37.5%	100% (5)	62%	48%	68%
DUBIN-MINDELL-BLOOME (10) (Long Island)							
Present Use (kwh/yr)							
Savings, 1995		25%		25%	25-40%		10%
NATURAL RESOURCES DEFENCE COUNCIL (27) (Pacific Northwest Ltd)							
Use 1975 (kwh/yr)	4442	1108	1662	917	672 (3)	334-464	1008
Savings 1985	16%	6%	15%	6%	-5%	46-	25%
Savings 1995	21%	11%	23%	6%	-3%	50%	40%
AVERAGE SAVINGS (4) INDICATED	16	28	30	15	43 (6)	48	35

1. As high as 90% with load management and 100% with solar.

2. Using fluorescent lights, lower wattage and bulk metering.

3. The negative sign indicates an increase in per unit consumption (due to increased size of units)

4. Where two values in one report are given, the average is used in calculation.

5. The savings of 100% due to shift towards natural gas is excluded.

6. Since the Pacific Northwest study reflects an increase in capacity which overshadows efficiency improvements, it has been excluded. The other estimate considers efficiency only.

Several of the studies have included savings that could not be achieved until about 1995. Allowance is made for this in the next chapter when the implementation of these savings is considered.

Economic Cost

T.T. Woodson assessed the potential for saving electricity in the residential sector of the U.S.[34]. He concluded that by the year 2000, annual savings in residential electricity consumption in the range of 25-45 per cent appear economically and technically feasible. In addition he noted that savings of 15-25 per cent could be achieved immediately and in the near term by means of operational housekeeping changes and some capital investments and process equipment changes. Although Woodson's study included space heating, whereas the present study deals with it separately, his findings suggest that the magnitude of savings estimated above (28%) is feasible for Ontario.

Important questions remain about the precise nature of the costs of improving the efficiency of residential appliances. Moreover, it is questionable whether the Canadian appliance industry is capable of making the necessary changes independently of competitive producers in the U.S. and elsewhere, given the emphasis that buyers apparently place on initial costs to the neglect of operating expenses. It was not possible to address these questions in the present study and so the economic viability of the modifications to appliances listed in this section remains in doubt.

TABLE IV.14

POTENTIAL SAVINGS FROM INCREASED EFFICIENCY OF RESIDENTIAL APPLIANCES IN 1974

	1974[1] TOTAL ELECTRIC ENERGY CONSUMED (10^6 kwh)	PER CENT ENERGY SAVINGS	LOAD FACTOR	EQUIVALENT 1974 LOAD REDUCTION (mw)
Water Heating	7090	16%	.80	160
Cooking	2539	28%	.32	250
Lighting	1840	30%	.23	270
Drying	1040	15%	.24	70
Refrigeration	3295	43%	1.02	160
Television	1250	48%	.43	160
Air Conditioning[(2)]	251	35%	-	-
				1070 mw

1. Ontario Hydro, Energy Utilization, table 6.2-11 1976 (37)

2. The energy savings for air conditioning do not translate into a peak reduction since little air conditioning occurs at the time of peak

9. ELECTRICAL SAVINGS IN THE COMMERCIAL SECTOR

Technical Potential

In 1974 the commercial sector, which includes several very different types of business establishments and institutions, accounted for 27.2% of the total electrical energy supplied by Ontario Hydro. This was less than either the residential or industrial sectors, although the recent historical trend in commercial consumption of electricity shows that it is growing significantly faster than in the other sectors[(35)].

Ontario Hydro has analysed the contribution of the various components of the commercial sector to peak demand, using data for 1972. It also examined the end use of electricity within the commercial sector and the findings are summarized in table IV.15.

On the basis of the information given in table IV.15, Ontario Hydro estimated the potential savings in electricity consumption that could be obtained by improving the efficiency with which the electricity is used for such purposes as lighting, operating pumps, fans and service motors and resistance loads. These estimates of potential savings are displayed in table IV.16 both for 1972 and for 1984, the latter being based on a projected use of electricity in that year by Ontario Hydro.

Table IV.16 shows Ontario Hydro's estimate that energy savings of up to 4470 x 10^6 kwh could have been achieved in

TABLE IV.15

THE END USE OF ELECTRICITY IN THE COMMERCIAL SECTOR, 1972

	LIGHTING	PUMPS/ MOTORS	AIR COND-ITIONING	SERVICE MOTORS	RESISTANCE LOADS	TOTAL
Consumption (10^6 kwh)	6938	3968	1740	3370	1305	17230
% of Total Commercial Consumption	40.1	22.9	10.1	19.5	7.4	100%
Estimated Coincident Demand (mw)	1626	765	13	551	455	3510
Estimated Coincident Load Factor	.49	.59	1.53[1]	.7	.33	.58

1. The load factor for air-conditioning implies that the use of air-conditioning at the time of system peak (in winter) was significantly lower than the average yearly use; the major use would occur in the other seasons.

Source: Ontario Hydro, Memorandum to the Board of Directors, 1976, Schedule "A" (30)

TABLE IV.16

SUMMARY OF ELECTRIC ENERGY MANAGEMENT
POTENTIAL IN THE COMMERCIAL MARKET SEGMENT

	POTENTIAL SAVING	POTENTIAL LOAD SAVING 1972 (BASIS) mw	1984 mw	POTENTIAL ENERGY SAVING 1972 (BASIS) 10^6kwh	1984 10^6kwh
Lighting	up to 50%	up to 800	up to 1750	up to 3500	up to 7500
Pumps & Fans	up to 20%	100	350	800	1800
Service Motors	up to 10%	7	17	40	102
Resistance Loads	up to 10%	45	140	130	400
Total:		up to 952	up to 2257	up to 4470	up to 9802

Source: Ontario Hydro, Memorandum to the Board of Directors, 1976, Schedule "A" (27)

the commercial sector, corresponding to a capacity saving of 952 mw. For 1984, Ontario Hydro projects potential energy and capacity savings respectively of up to 9820 10^6 kwh and 2257 mw.

The magnitude of the savings estimated in the Ontario Hydro study corresponds closely to similar estimates made for two other areas: Long Island, New York[37] and the Pacific Northwest of the United States[38]. Significantly, both of these studies indicate that conservation levels above the estimate made by Ontario for 1984 are achievable further in the future.

Some of the measures examined by Ontario Hydro might be construed as involving a reduction in services, for example, lower levels of lighting and heating. Yet bearing in mind that larger savings than those estimated by Ontario Hydro may be possible beyond 1984, it is concluded that for the purpose of the present study, the estimates of potential electrical savings in the commercial sector shown in table IV.17 are not unduly optimistic.

TABLE IV.17

POTENTIAL ANNUAL ELECTRICAL SAVINGS IN THE COMMERCIAL SECTOR

USE	POTENTIAL SAVINGS
Lighting	40%
Pumps and Fans	15%
Service Motors	7%
Resistance Loads	7%

In Chapter V these estimates of potential savings are applied to the forecasts of electricity consumption in the commercial sector and converted, by means of the load factors given in table IV.15, to capacity savings.

Economic Costs

In the course of the present study no detailed information was found relating to the costs of improving the efficiency of electrical use in the commercial sector. Some writers believe that the costs are quite modest[(39)] and Ontario Hydro gives an example showing that switching fluorescent lamps off when they are not in use saves the user money, even though the lamps might deteriorate more rapidly as a result[(40)]. Moreover, some of the other conservation measures discussed in the Ontario Hydro report would also result in net savings.

However, the fact remains that comprehensive cost estimates are not available and so it has not been possible to reach any firm conclusion as to the cost competitiveness of the measures discussed in this section.

10. ELECTRICAL SAVINGS IN THE INDUSTRIAL SECTOR

Technical Potential

Ontario Hydro has studied the use of electricity by manufacturing industries and assessed the potential for energy management[(41)]. In 1974, the industrial demand coincident at the time of system peak was about 4,500 mw and more than 40% of that year's electrical energy was consumed by industry[(42)]. Electrical motors created almost 75% of the industrial demand, process requirements and lighting accounting for the remainder.

In its assessment of the potential for energy management, Ontario Hydro concluded that a reduction of more than 500 mw from the industrial use of electricity supplied by Hydro was possible. This could be achieved by a combination of peak shaving and energy conservation (100 mw), load shifting (271 mw) and self-generation (150 mw). The measures noted in the Ontario Hydro study include: using standby generators, computerizing the control of energy use, improved lighting systems, using compressed air, more efficient equipment.

Since cogeneration, which is included in self-generation, has been dealt with separately in this study, savings from this activity will not be included here[(43)]. The remaining savings from peak shaving, energy conservation and load shifting estimated by Ontario are 371 mw, more than 8% of the 1974 peak industrial load. It is reasonable to assume, therefore, that the potential for peak reduction will be at least 8% for each year into the future[(44)].

In order to utilize this figure in the next chapter, an industrial load factor is required to relate the projected energy demands of industry in chapter II to the associated capacity requirements. It is these estimated capacity requirements which can be reduced by 8% on the basis of the savings assumed possible in the Ontario Hydro study.

Ontario Hydro has published a load factor for its industrial customers of .62[45]. However, this does not correspond to the figures for coincident peak demand and annual energy consumed that have been published elsewhere by Ontario Hydro. The coincident demand figure of 4,500 mw cited above, combined with the energy figure of 31.4×10^6 mwh[46] implies a load factor of .8. Although this seems somewhat high, in order to remain on the conservative side, this value 4.8 will be used in all subsequent calculations.

Economic Cost

It has not been possible to estimate the costs necessary to secure these potential savings for industrial users of electricity. The range of activities involved is very great and costs can be expected to vary from one establishment to another. Although some writers strongly suggest that such savings are cost competitive with the alternative of expanding central generating facilities[47], the absence of any comprehensive cost estimates makes it impossible to conclude that this is, in fact, the case.

11. SOLAR SPACE AND WATER HEATING

Technical Potential

During the past few years increasing attention has been paid to the potential role that solar energy could play in reducing the demand for other forms of energy. The availability of energy from the sun is not disputed. It is the technical potential for utilizing this energy and the associated economic costs which provide the focus for debate.

The technical issues relate to such aspects as active solar versus passive, collector designs, storage medium and capacity, life of the equipment, insulation and building design[48]. Individually important as they are, these issues will ultimately be resolved in terms of economics. There exists a wide range of technical means for using solar energy and it is economic criteria which will decide which are the best.

Economic Potential

Two recent Canadian studies conclude that solar energy for space and water heating is likely to be competitive with electrical energy for the same purpose within the next five years[49]. This conclusion was arrived at by comparing the expected lifetime costs of the different heating systems.

Other studies in the U.S. and other countries concur with the view that solar space and water heating is or will shortly be competitive with other forms of heating, especially electrical[50].

Of considerable relevance to Canada is the conclusion reached in a study conducted at the University of New Mexico, that solar heating is more economic in the northern than the southern states owing to the greater requirements for heat energy in the north, and that it is already cheaper than electric heat in more than half the states[51].

In contrast to the above studies, conclusions reached by Ontario Hydro and by the Ontario Ministry of Energy are much less favourable towards solar energy for space and water heating . These different conclusions stem from the use of different assumptions, relating in particular to the costs of the equipment and the future price of electricity[52].

Rather than attempt to resolve the issue here as to the competitiveness of solar space and water heating this study will make extensive use of two reports on solar energy prepared by the I.B.I. Group for the Royal Commission[53]. As the authors of the reports recognize, the rate of implementation of solar energy in the residential, commercial and industrial sectors will depend critically on government policy in terms of financial and legislative incentives. In one of the scenarios they consider (the high-high scenario) they do allow for some modestinitiatives in this area[54], but much more could be done and this would increase the rate of implementation beyond what they presently believe is likely to happen.

A further point is that in the economic assessment of the solar options, the I.B.I. studies adopt the perspective of

the potential buyer. That is, they assess the competitiveness of solar heating from the point of view of an individual or a company planning to buy a heating system. In the case of new buildings the cost comparison is done on a life-cycle basis. When retrofitting is examined, it is conservatively assumed that the cost "comparison is made of the actual cost of conventional heating in the year in question versus the average annual cost of solar heating, capitalized over the coming 20 years"[55]. In other words they assume that no one will retrofit their buildings to use solar energy until it is no more costly than conventional methods in the first year of operation.

From the point of view of public policy, a more appropriate cost comparison than that used by I.B.I. would be between the costs of capturing solar energy for space and water heating and the costs of supplying equivalent amounts of energy from other sources. To the extent that what the buyer has to pay for these other energy sources is less than the cost of making them available, the conclusions of the I.B.I. reports understate the real cost competitiveness of the solar systems.

In the next chapter the effects of solar space and water heating in Ontario's electrical supply system will be assessed in terms of an implementation scenario that lies in the middle of I.B.I.'s low-low and high-high scenario[56]. As such it may be regarded as a rate of implementation that is cost competitive with the alternative of providing electric heat from new large generating stations.

12. LOAD MANAGEMENT

Technical Potential

Load management refers to a wide range of activities which are capable of raising an electrical utility's load factor defined as the ratio of average load to peak load. Other things being equal, the higher the load factor the smaller is the generating capacity required to deliver a given quantity of electrical energy over a period of time. This means that if consumers of electricity can be induced to re-schedule their activities so that the system load is evened out and the peak demand reduced, the rate of expansion of generating capacity can be curtailed.

In a study for the Royal Commission[57], Leighton and Kidd review the theory of and international experience with the two main methods of load management: pricing incentives, whereby peak power is sold at a higher price than off-peak power; and the direct control of utility loads, whereby some loads, particularly industrial, can be reduced directly by the utility. They point out that in Europe it is common to see pricing incentives coupled with the direct control of loads by utilities.

The success of these European load management practices is indicated in table IV.18.

Variations in utility load factors are, of course, attributable to other causes in addition to the specific load management

TABLE IV.18

UTILITY ANNUAL LOAD FACTORS 1973-1974

COUNTRY	ANNUAL LOAD FACTOR %
Austria	83.4
Luxembourg	80.2
France	77.2
Belgium	76.3
Germany (Federal Republic)	75.0
Italy	71.8
Netherlands	70.9
Ontario	69.7
United States	65.5

Source: Leighton and Kidd, p.13, 1976 (22)

practices of the utilities. However, it should be recognised that in 1973-74, the year for which the load factors are given in table IV.18, Ontario Hydro's load factor of 69.7% was higher than for any year since 1935, and considerably higher than the 65.8% that Ontario Hydro is projecting for its future operations[58].

In light of this it is assumed in the present study that a load factor of 70% is achievable in Ontario if suitable load management practices are implemented. This is consistent with Leighton and Kidd's conclusion that in Ontario there is "a potential for shaving annual maximum demand by a few percent by managing selected loads over the day time and early evening peak load period, on each working day throughout the winter months"[59]. Such an increase in the system load factor would not entail a reduction in the amount of electrical energy available to Ontario Hydro's customers. It would only reflect changes in the time at which the electricity is used.

Economic Cost

Leighton and Kidd do not report specifically on the costs of load management. However, they do note that more sophisticated metering equipment is necessary to implement peak load pricing schemes. Furthermore, the various means of remote switching that would be necessary for the utility to directly curtail load would also involve costs. One indication of the comparatively low level of these costs is the estimate that ripple control systems cost approximately $120 per customer (1977) and the potential exists to save several kw per controlled customer[60].

13. DISTRICT HEATING

Technical Potential

District heating refers to a variety of heating systems in which heat is generated at a central location and transmitted by water or steam to other buildings, which may be located nearby or at a considerable distance.

The major sources of heat that have been considered to supply district heating systems are:

- electrical generating stations
- refuse incineration
- industrial boilers

In the present study considerable emphasis has been placed on the potential for industrial cogeneration of electricity. To the extent that this potential is realised, it would pre-empt the use of industrial waste heat for use in a district heating system. For this reason, this particular souce of heat is not considered further.

Refuse incineration could be used as a heat source in Ontario but probably not on a large scale. Of the many studies which have examined the widespread application of district two of the most optimistic concentrate on the utilization of steam or hot water from electrical generating stations. This potential represents the most promising heat source for district heating[61, 62].

Existing and planned electrical generating stations can be operated in dual mode so as to produce an optimal combination of electricity and steam to maximize the output of useful energy. This has the effect of raising the overall energy efficiency of thermal-electric generating stations from about 33% to more than 80%.

However, to achieve this higher efficiency, an electrical generating station rated at say 2,000 mw capacity would only be capable of supplying approximately 1,500 mw of electricity[61].

From the point of view of a comprehensive energy strategy, the crucial question is whether this loss of 500 mw capacity can be justified in terms of the production of useful energy in the form of hot water or steam. Since this energy will be used for heating it will reduce the demand for heat energy obtained from other sources, notably fossil fuels and electricity. The value of this decreased heat energy demand may well exceed the value of the reduced generating capacity.

For the purposes of the present study, it is not the reduced demand for all other forms of heat energy which is relevant to the consideration of district heating. The central question here is whether the adoption of district heating will reduce the requirements for new generating capacity and this must be assessed by comparing the reduced generating capacity resulting from dual mode operations with the reduced demand for electric heating.

In an attempt to make this comparison for Ontario it was assumed that up to 75% of the population between Oshawa and Hamilton could be connected to district heating schemes deriving energy from the electrical generating stations in the region[63].

Table IV.19 shows estimates of the number of electrically heated units in the region in 1977 that could be served by district heating, which, of course, would also serve homes presently heated by other means. The table also shows estimates of the energy and peak electricity savings that would result. The results suggest that 255 mw could be removed from Ontario Hydro's present capacity by using district heating in place of the electrical heating that is in use in the Oshawa-Hamilton region.

To estimate the effect of this district heating program on the power system capacity, the total heat requirement must be estimated i.e. the heat required by all of the homes connected to the district heating system including those heated by fossil fuels. Homes in Ontario in 1976 required about 2,300 x 10^6 gallons of home heating oil equivalent to about 230 x 10^{12} Btu (at 60% conversion efficiency)[64]. An estimate of the heating requirement for one third of the population is then about 77 x 10^{12} Btu. Assuming that insulation improvement could reduce demand as much as 38%, a lower estimate of the requirement would be 47 x 10^{12} Btu.

TABLE IV.19

AN ESTIMATE OF THE POTENTIAL ELECTRICAL ENERGY SAVINGS IN THE OSHAWA - HAMILTON REGION OF ONTARIO FOR 1977

	# OF UNITS DISTRICT HEATING (1)	UNIT DEMAND		TOTAL DEMAND REDUCED BY DISTRICT HEATING	
		ENERGY (2) (10^6 Btu)	PEAK (3) (kw)	ENERGY (10^9 Btu)	PEAK (mw)
EXISTING					
Single Family	37,000	60.0	5.0	2260	189
Apartment	33,000	24.0	2.0	790	66
TOTAL:	70,000			3050	255

1. 1/3 of electrically heated homes in Ontario table IV.9.
2. Table IV.10
3. Table IV.10

To supply this much heat (47×10^{12} to 77×10^{12}) a dual-mode station would concommittantly produce 1700 mw to 2700 mw. The plant's original electrical capacity would be 2300 mw to 3600 mw with an overall capacity reduction of 600 to 900 mw[(65)].

This means that the net effect on electrical generating capacity of these particular district heating programs would be the difference between the reduced requirements of 255 mw and the reduced capacity of 600 mw - 900 mw, i.e. the generating system would have to grow by 245 mw - 645 mw.

Because of this result, district heating is not considered further in this study even though district heating may be cost competitive with other sources of heat energy and would make sense if evaluated within the context of a broad energy policy.

FOOTNOTES

1. It may be noted that several measures are not considered: substitution of other fuels (except solar energy) for electricity; using urban design to influence electricity consumption patterns; heat pumps; construction of many, locally situated small fossil-fuelled generating stations; increased capacity for off-peak storage of electricity.

2. Leighton and Kidd Ltd., Report on Industrial By-Product Power, 1977 (22)

3. Leighton and Kidd (22)

4. Leighton and Kidd, p.14 (22)

5. Mr. Kidd informed us that their estimate is taken from A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining, and Paper and Pulp Industries, 1976 (13) No adjustments for price changes from 1976 to 1977 were made owing to a lack of information.

6. This figure was described as reasonable in a personal communication from Mr. Kidd.

7. Methanol in Ontario, 1976 (8)

8. Ontario Hydro, Generation Planning Processes, Fig. 11-6 , 1976 (39)

9. J.P.R. Associates, The Feasibility of Generating Electricity, p.108 , 1975 (20)

10. Ontario Hydro, Generation-Technical, Fig. 2.1.18-2 1976, (40)

11. The J.P.R. study assumes \$11/green ton. (20)

12. C.K. Brown and D.F. Warne, An analysis of the Potential for Wind Energy Production in North-western Ontario, Ontario Research Foundation, 1975. (6)

13. Wind Workshop II (Proceedings), 1975, Mitre Corp. p.58 which includes discussion of megawatt wind turbines. (25)

14. Personal communication from J. Templin, N.R.C., Ottawa, Feb. 1976.

15. Brown and Warne, 1975 (6)

16. Mitre Report, p.58. 1977 (25)

17. Ontario Hydro, Generation-Technical, Vol.I, p.2.2-1 1976 (40)

18. Personal communication from Ontario Hydro.

19. Ontario Hydro, Generation-Technical, Vol.I, p.2.2-3 1976 (40)

20. Ontario Hydro, Generation: non-nuclear, Vol I, p.4, 1977 (38)

21. Ontario Hydro, Generation: non-nuclear, Vol.I, p.6 1977 (38)

22. Planning of the Ontario Hydro East System, Ontario Hydro, 1976, Vol. I, chapter 9. (42)

23. A New Public Policy Direction for Ontario Hydro, Select Committee of the Legislature, pp. III, 35-36 (51)

24. See H.A. Smith, Reliability, Costs and Values Associated with Reserve Peak Generating Capacity Ontario Hydro East System 1976 - 1985, Ontario Hydro, 1976 (54)

25. Scanada Consultants Ltd., Thermal Efficiency and the Potential for Conservation, 1976, p.11-12 (50)

26. Scanada, Thermal Efficiency, 1976 (50)

27. Ontario Hydro, Memorandum to the Board of Directors, Schedule "D", 1976 (30)

28. Scanada, Thermal Efficiency 1976 (50)

29. HUDAC, A Builders Guide to Energy Conservation, Tables 3 and 4. (17)

30. A figure of 1,500 sq. ft. is commonly used.

31. HUDAC, A Builders Guide to Energy Conservation, derived from figures in Tables 3 and 4 (17).

32. R.M.R. Higgin, Solar Heating of Buildings in Ontario, 1976 (16)

33. - Ontario Hydro, Memo to the Board, Schedule C, 1976, Appendix VI. (32)

- "Background Data for Probe's Issue Paper on a Nuclear Moratorium", Energy Probe, 1977. (12)

- Projecting an Energy-Efficient California, Goldstern, Rosenfeld, 1975, Chapter I (14)

- A Study of Existing Energy Usage on Long Island, Dubin-Mindell-Bloome Associates, 1975 (10)

- Choosing an Electrical Energy Future for the Pacific Northwest, Natural Resources Defence Council (FRDA), 1977, Table 32. (27)

34. T.T. Woodson, "Residential Energy Use", Efficient Electricity Use, C.B. Smith (ed), 1976 (55)

35. Ontario Hydro, Energy Utilization, Table 6.2-2 , 1976 (37)

36. Ontario Hydro, Memorandum to the Board of Directors, 1976, Schedule A. (40)
Retail trade and services accounted for more than 45% of the commercial peak.

37. A Study of Existing Energy Usage on Long Island, Dubin-Mindell-Bloome Associates, Table 20, 1975 (10)

38. Choosing an Electrical Energy Future for the Pacific Northwest - An Alternative Scenario, Natural Resources Defence Council, 1977 (27)

39. See, for example, Taussig and Smith "Commercial Energy Use" in C.B. Smith (ed) (55)

40. Ontario Hydro, Memorandum to the Board of Directors, Conservation Plan for the Office Building Lighting Market Segment of the Commercial Market, Schedule A., 1976 (27)

41. Evaluation of Electrical Energy Management Potential in Industry, Ontario 1976 - Released as separate document PMA 76-6 and as part of Memorandum to the Board of Directors, Schedule F, 1976 (35)

42. Ontario Hydro, Memorandum to the Board of Directors, Schedule G, 1976 (36)

43. Note that Ontario Hydro's estimate of the potential for cogeneration is low in comparison with that of Leighton and Kidd.

44. The Ontario Hydro report from which this information comes cites an estimate of the energy savings corresponding to these capacity savings of about 4.2%.

45. Ontario Hydro, Memorandum to the Board of Directors, Schedule F., 1976 (35)

46. Ontario Hydro, Electrical Utilization and the Role of Electricity, 1976 (37)

47. Efficient Electricity Use, C.B. Smith (ed), 1976, p.814 (55)

48. See, for example, J.R. Sasaki Solar-Heating Systems for Canadian Buildings, December 1975 (49)

49. - M.K. Berkowitz Implementing a Solar Energy Technolodgy in Canada: The Costs, Benefits and Role of Government, 1977 (4)

- Middleton Associates, Canada's Renewable Energy Resources: An Assessment of Potential, 1976 (24)

50. For example, H.C. Petersen, The Impact of Tax Incentives and Auxiliary Fuel Prices on the Utilization Rate of Solar Energy Space Conditioning, 1976 (46)

51. This study was done for the House-Senate Joint Economic Committee and is reported in Vol. 7, Solar Energy Society of Canada p.1.(53)

52. - See: A.G. Barnstaple, An Examination of the Potential for Solar Energy Utilization in Ontario, Ontario Hydro, 1975 (2)

- R.M.R. Higgin , Solar Heating for Buildings in Ontario, 1976 (16)

- Ontario Ministry of Energy, Ontario's Energy Future, 1977 (43)

- Ontario Hydro,Energy Utilization and the Role of Electricity, 1976 (37)

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53. - I.B.I. Group, Solar Heating: An Estimate of Market Penetration, 1977 (18)

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54. I.B.I. Group, Solar Heating, p.35 (18)

55. I.B.I. Group, Solar Heating, p.7 (18)

56. I.B.I. Group, Solar Heating, p.35 (18)

57. Leighton and Kidd, Report on Electrical Load Management Possibilities, 1976 (22)

58. Ontario Hydro, Load Forecast 1977, No. 770214, p.26 (41)

59. Leighton and Kidd, p.35 (19)

60. R. Bezdek, Analysis of Policy Options for Accelerating Commercialization of Solar Heating and Cooling Systems, 1977 (5)

61. "Prospects for District Heating in the United States", Karksheck, Powell, Beardsworth, <u>Science</u>, March 1977 (21)

62. <u>Energy Conservation through District Heating</u>, Compiled by Swedish Trade Commission, 1976 - 1977 (56)

63. This corresponds to about 33% of Ontario's population. Karksheck,Powell and Beardsworth (21) expressed the view that 40% of the U.S. population could be economically connected to distant heating schemes.

64. Scanada, <u>Thermal Efficiency in Existing Housing</u>, 1976 (50)

65. The combined capacities of the existing generating stations in the Oshawa-Hamilton area is 5,500 mw of which 2,000 mw is nuclear.

CHAPTER V

THE QUESTION ANSWERED

1. INTRODUCTION

Chapter I posed the question "to what extent would it be possible to postpone the introduction of another large generating station after 1988, the date at which Darlington G.S. is expected to begin full operation, without any reduction in the services that the electrical energy would have provided?"

Chapter II projected the end use of electricity in Ontario over the next 30 years and considered the relations among end use, energy and power.

In Chapter III estimates were made, on the basis of Ontario Hydro data, of the financial savings resulting from postponing the introduction of central generating facilities beyond 1988.

Chapter IV reviewed a wide range of measures which, individually or combined, have some potential for reducing the requirement for additional large generating facilities after Darlington G.S. However, no attempt was made in that chapter to develop these measures into a consistent program of implementation.

Ideally, it would be desirable to combine the various options so as to obtain the greatest savings in Ontario Hydro's capacity requirements, at the least social, environmental and economic cost. This could then be compared with Ontario Hydro's expansion program to arrive at the optimal way of providing the services implicit in Ontario Hydro's load forecast. Further, and beyond the scope of this study, one might consider the implication of alternative patterns and levels of end use to arrive at a consciously conceived demand goal as an integral part of an energy strategy for Ontario.

Unfortunately, optimization even of the economic costs is not possible on the basis of the information gathered in the previous chapters. The estimates of the potential contribution and cost of the different measures examined vary in quality. For this reason a more pragmatic approach to developing a consistent program has been adopted. The measures are taken in sequence, beginning with those for which the estimates are considered most significant in terms of reliability, magnitude and cost. As additional measures are taken into account, the total program is built up in a manner which recognizes duplications and incompatibilities so as not to exaggerate the contribution of the program as a whole.

2. IMPLEMENTING COGENERATION IN ONTARIO

It has been estimated that Ontario presently has about 500 mw of cogeneration capacity and that a reasonable target capacity

for 1985 is about 3,000 mw[1]. The implementation program between 1977 and 1985 considered feasible by Leighton and Kidd was extended in the previous chapter to the year 2007. Such an implementation program appears capable of displacing the first large generating station planned by Ontario Hydro to come into service after Darlington G.S. The proposed in-service date of the fourth unit of E15, a 4 x 516 mw plant, is October 1989. Table IV.1 shows that the potential cogeneration capacity in 1989 is an estimated 2699 mw. Since 500 mw are already in place, this amounts to a net addition of 2199 mw capacity, some 135 mw in excess of the 2064 mw of E15.

A major problem with their specific implementation program is that it begins very quickly, at considerable expense, and brings substantial amounts of generating capacity on stream several years in advance of the in-service dates of E15 and subsequent plants. In order to arrive at a more appropriate rate of implementation given the specific purpose of the present study, a model has been developed to allow the examination of alternative rates of implementation.

A Model for Examining the Implementation of Cogeneration in Ontario

The model described in this section allows for four kinds of activities[2]:

(i) retrofitting existing industrial steam generating capacity;

(ii) implementation of cogeneration in new steam generating capacity;

iii) preparation of new steam generating capacity for retrofitting at some future date;

iv) retrofitting prepared steam generating capacity.

Each of these activities contributes to the implementation of cogeneration in a different way and at different cost. The most economical approach is to install the necessary equipment as new industrial steam capacity is introduced. However, this limits the rate at which cogeneration can be expanded in Ontario to the modest rate of expansion expected for steam generating capacities. Moreover, this rate is not the optimum for implementing cogeneration given the objective of displacing additions to Ontario Hydro's system which are planned for 1988 and beyond. This is why allowance is made in the model for new steam capacity to be prepared for retrofitting at a later date, closer to the time the electricity will be required.

Retrofitting existing industrial steam facilities for cogeneration, although more costly than in the case of new steam facilities, also has a role and is allowed for in the model. The purpose of the model is to examine the consequences of various rates of implementing cogeneration in terms of the electrical generating capacity that becomes available in any year, and the costs which must be incurred.

Although the model is conceptually very simple, in that it is no more than a means for systematically combining the four activities identified above, it is sufficiently complex to require exposition in the form of equations. What is more

significant is that the model illustrates the way in which the implementation of the measures described in the previous chapter should be studied. Indeed, a more general model would examine the implementation of these measures simultaneously and conceivably account for their likely impact on Ontario Hydro's generation and transmission system.

The construction of such a model, which could prove most useful for evaluating alternative energy options for Ontario, was beyond the scope of this study. However, the far more modest model developed below provides an indication of how the technical and economic aspects of implementing energy measures might usefully be approached in the future.

Definitions

MSD_1^t	=	new maximum steam demand in year t
MSD_2^t	=	unprepared maximum steam demand at the start of year t. (i.e. no special provisions made to accommodate cogeneration.)
MSD_3^t	=	prepared maximum steam demand at the start of year t. (i.e. special provisions made to accommodate cogeneration.)
MSD_4^t	=	new prepared maximum steam demand in year t
MSD^o	=	steam demand in the base year (1977)
MSD^u	=	steam demand in the base year not being used for cogeneration

N.B.

MSD_1^t, and MSD_4^t are flows; MSD_2^t, MSD_3^t, MSD^o and MSD^u are stocks. All are in units of lbs/hr.

U_1^t = utilization rate of MSD_1^t for cogeneration in year t

U_2^t = utilization rate of MSD_2^t for cogeneration in year t

U_3^t = utilization rate of MSD_3^t for cogeneration in year t

U_4^t = utilization rate of MSD_1^t for preparing for future cogeneration in year t

CAP_1^t = electrical generating capacity from the use of new steam capacity for cogeneration added in year t

CAP_2^t = electrical generating capacity from the use of existing (unprepared) steam capacity for cogeneration added in year t

CAP_3^t = electrical generating capacity from the use of prepared steam capacity for cogeneration added in year t

COC_1^t = annual capital, operating, maintenance and fuel costs associated with CAP_1^t

COC_2^t = annual capital, operating, maintenance and fuel costs associated with CAP_2^t

COC_3^t = annual capital, operating, maintenance and fuel costs associated with CAP_3^t

COC_4^t = annual capital costs of preparing new steam capacity for cogeneration at some future date

Using these definitions four equations can be established which define the implementation rate of cogeneration.

t = 0 in the base year (1977 in the present case)

$$MSD_1^t = (1.05^t - 1.05^{t-1}).\ MSD^o \qquad \text{V.1.}$$

Equation V.1. states that the incremental new maximum steam demand in any year after 1977, the base year, grows at a compound annual rate of 5% over the steam demand in 1977.

$$MSD_2^t = MSD^u + \sum_{t=1}^{t-1} \left[MSD_1^{t-1} (1-U_1^{t-1} - U_4^{t-1}) \right] \qquad \text{V.2.}$$

Equation V.2. states that unprepared maximum steam demand at the start of year t equals the unprepared maximum steam demand at the start of the base year, plus that part of the new maximum steam demand of the previous years which was neither used for cogeneration nor prepared for future cogeneration.

$$MSD_3^t = MSD_3^{t-1} (1 - U_3^{t-1}) + MSD_4^{t-1} \qquad \text{V.3.}$$

Equation V.3. states that the prepared maximum steam demand at the start of year t equals the prepared maximum steam

demand at the start of the previous year, minus the portion of that which was retrofitted for cogeneration. This is added to the portion of new maximum steam demand in the previous year that was prepared for cogeneration facilities to be installed at a later date.

$$MSD_4^t = MSD_1^t \times U_4^t \qquad \text{V.4.}$$

Equation V.4. states that the incremental prepared maximum steam demand in year t is equal to the portion of the incremental new maximum steam demand of that year which is prepared for future cogeneration.

The next three equations relate the utilization of maximum steam demands to electrical generating capacity.

$$CAP_1^t = MSD_1^t \times U_1^t \times 60 \qquad \text{V.5.}$$

Equation V.5. states that the new electrical generating capacity from the use of new steam capacity in year t is equal to the new maximum steam demand in that year multiplied by the utilization factor, multiplied by an assumed installed capacity of 60 kw per 1000 lbs/hr of maximum steam demand.

$$CAP_2^t = MSD_2^t \times U_2^t \times 60 \qquad V.6.$$

$$CAP_3^t = MSD_3^t \times U_3^t \times 60 \qquad V.7.$$

Equations V.6. and V.7. relate new cogeneration capacity from using unprepared and prepared maximum steam demands respectively, to incremental steam demands and utilization rates.

In order to use these equations to establish an implementation program for cogeneration, values for the base year maximum steam demands and for the utilization factors are necessary. Tables V.1. and V.2. show the values used in the present study.

The values for MSD^o in table V.1. are taken from Leighton and Kidd's study (see Chapter IV). MSD^u is lower than MSD^o for the first category of steam demand to account for the 500 mw of cogeneration capacity that is already in place in Ontario.

Leighton and Kidd's assumptions about the expansion of cogeneration in Ontario were described earlier. The utilization factors shown in table V.2. assume a phased program culminating in 1988 in a rate of introduction for cogeneration equal to that which Leighton and Kidd suggest is possible immediately. Thus, their assumed rates of utilization of new steam demand (U_1) are not achieved until 1988.

The proportion of existing capacity that is retrofitted (U_2) is phased in over a 10 year period rather than being achieved at once. Moreover, neither of these activities are assumed

TABLE V.1

VALUES FOR BASE YEAR MAXIMUM STEAM DEMANDS USED TO ESTABLISH AN IMPLEMENTATION PROGRAM FOR COGENERATION

PARAMETER	CATEGORY OF STEAM DEMAND		
	MSD > 500,000 lbs/hr	500,000 lbs/hr > MSD > 100,000 lbs/hr	MSD < 100,000 lbs/hr
MSD^o	17.9×10^6	11.4×10^6	14.2×10^6
MSD^u	9.6×10^6	11.4×10^6	14.2×10^6

Source: Leighton and Kidd, 1977 (22)

TABLE V.2

ASSUMED VALUES FOR THE UTILIZATION FACTORS

YEAR	CATEGORY OF STEAM DEMAND											
	MSD > 500,000 lb/hr				500,000 lb/hr > MSD > 100,000 lb/hr				MSD < 100,000 lb/hr			
	U_1	U_2	U_3	U_4	U_1	U_2	U_3	U_4	U_1	U_2	U_3	U_4
1978	.0	.0	.0	.2	.0	.0	.0	.15	.0	.0	.0	.05
1979	.0	.0	.0	.4	.0	.0	.0	.3	.0	.0	.0	.1
1980	.0	.0	.0	.6	.0	.0	.0	.45	.0	.0	.0	.15
1981	.0	.0	.2	.8	.0	.0	.2	.6	.0	.0	.0	.2
1982	.2	.0	.4	.6	.15	.0	.4	.45	.1	.0	.25	.15
1983	.4	.01	.6	.4	.3	.05	.6	.3	.2	.0	.5	.1
1984	.6	.11	.8	.2	.45	.11	.8	.15	.3	.01	.75	.0
1985	.8	.21	1.0	.0	.6	.17	1.0	.0	.4	.03	1.0	.0
1986	1.0	.2	1.0	.0	.75	.07	1.0	.0	.4	.04	1.0	.0
1987	1.0	.03	1.0	.0	.75	.0	1.0	.0	.4	.02	1.0	.0
1988 to 2007	1.0	.0	1.0	.0	.75	.0	1.0	.0	.4	.0	1.0	.0

to start until 1982[3]. In the meantime, allowance (U_4) is made for new steam capacity to be prepared (U_3) for retrofitting at a later date.

Tables V.3. - V.5. show the numerical results obtained by using the data described in Chapter IV, in conjunction with the implementation model consisting of equations V.1. to V.7.[4]. The most important columns are those which show the total annual costs and the total available generating capacity for each category of maximum steam demand. Table V.6. is a summary of the data shown in tables V.3. - V.5. and shows the annual expenses for capital, operation and maintenance, and fuel associated with the electrical generation capacity available in each year.

According to table V.6. the implementation of cogeneration in Ontario in the manner assumed would make available installed capacity of 2100 mw by the year 1990, which would be in addition to the 500 mw of cogeneration capacity that already exist in Ontario. This is more than sufficient to remove the requirement for E15, the 4 x 516 mw plant that is planned as the next station to succeed Darlington G.S.

It is not immediately obvious from table V.6. whether cogeneration on the scale suggested is cheaper than the expansion of Ontario Hydro's generation system, even though Leighton and Kidd's study suggests that cogeneration, if financed by Ontario Hydro, would be cheaper than a large fossil-fuelled

TABLE V.3

AN IMPLEMENTATION PROGRAM FOR COGENERATION USING INDUSTRIAL BOILERS WITH MAXIMUM STEAM DEMANDS GREATER THAN 500,000 lbs/hr

YEAR	CAPITAL, OPERATING, MAINTENANCE AND FUEL COSTS (1977 dollars x 10^3)					GENERATING CAPACITY (mw)			
	COC_1	COC_2	COC_3	COC_4	TOTAL ANNUAL COSTS	CAP_1	CAP_2	CAP_3	TOTAL AVAILABLE CAPACITY
1978	0	0	0	56.8	57	0	0	0	0
1979	0	0	0	119.3	176	0	0	0	0
1980	0	0	0	187.9	364	0	0	0	0
1981	0	0	1281.4	263.0	1909	0	0	12.4	12.4
1982	1391.7	0	3588.3	207.2	7096	13.1	0	34.8	60.3
1983	2922.7	1175.9	4575.2	145.0	15915	27.4	8.7	44.4	140.8
1984	4603.2	10267.8	3480.8	76.1	34342	43.2	76.2	33.8	293.9
1985	6444.5	19359.7	1483.6	0	61630	60.4	143.6	14.4	512.4
1986	8458.4	18183.8	0	0	88272	79.3	134.9	0	676.6
1987	8881.3	2351.9	0	0	99506	83.3	17.4	0	827.4
1988	9325.4	0	0	0	108831	87.5	0	0	914.9
1989	9791.6	0	0	0	118623	91.8	0	0	1006.7
1990	10281.2	0	0	0	128904	96.4	0	0	1103.1
1991	10795.3	0	0	0	139699	101.3	0	0	1204.4
1992	11335.0	0	0	0	151034	106.3	0	0	1310.7
1993	11901.8	0	0	0	162935	111.6	0	0	1422.4
1994	12496.9	0	0	0	175432	117.2	0	0	1539.6
1995	13121.7	0	0	0	188554	123.1	0	0	1662.7
1996	13777.8	0	0	0	202332	129.2	0	0	1791.9
1997	14466.7	0	0	0	216798	135.7	0	0	1927.6
1998	15190.0	0	0	0	231931	142.5	0	0	2070.1
1999	15949.5	0	0	0	247705	149.6	0	0	2219.7
2000	16747.0	0	0	0	264088	157.1	0	0	2376.8
2001	17584.3	0	0	0	280673	164.9	0	0	2541.7
2002	18463.6	0	0	0	296426	173.2	0	0	2714.9
2003	19386.7	0	0	0	310108	181.8	0	0	2896.7
2004	20356.1	0	0	0	314149	190.9	0	0	3087.7
2005	21373.9	0	0	0	300514	200.5	0	0	3288.2
2006	22442.6	0	0	0	267785	210.5	0	0	3498.7
2007	23564.7	0	0	0	225803	221.0	0	0	4219.7

TABLE V.4

AN IMPLEMENTATION PROGRAM FOR COGENERATION USING INDUSTRIAL BOILERS WITH MAXIMUM STEAM DEMANDS LESS THAN 500,000 lbs/hr AND GREATER THAN 100,000 lbs/hr

	CAPITAL, OPERATING, MAINTENANCE AND FUEL COSTS (1977 dollars x 10^3)					GENERATING CAPACITY (mw)			
YEAR	COC_1	COC_2	COC_3	COC_4	TOTAL ANNUAL COSTS	CAP_1	CAP_2	CAP_3	TOTAL AVAILABLE CAPACITY
1978	0	0	0	30.8	31	0	0	0	0
1979	0	0	0	64.7	96	0	0	0	0
1980	0	0	0	101.9	197	0	0	0	0
1981	0	0	627.0	142.7	967	0	0	6.0	6.0
1982	695.9	0	1755.8	112.3	3531	6.3	0	16.7	28.9
1983	1461.4	5541.3	2238.7	78.6	12851	13.1	39.1	21.3	102.3
1984	2301.7	12361.5	1703.2	41.3	29259	20.7	87.1	16.2	226.3
1985	3222.4	19381.2	725.9	0	52588	28.9	136.6	6.9	398.8
1986	4229.4	8100.3	0	0	64918	38.0	57.1	0	493.9
1987	4440.9	0	0	0	69359	39.9	0	0	533.8
1988	4662.9	0	0	0	74022	41.9	0	0	575.7
1989	4896.0	0	0	0	78918	44.0	0	0	619.7
1990	5140.8	0	0	0	84059	46.2	0	0	665.9
1991	5397.9	0	0	0	89457	48.5	0	0	714.3
1992	5667.8	0	0	0	95124	50.9	0	0	765.3
1993	5951.2	0	0	0	101076	53.5	0	0	818.7
1994	6248.7	0	0	0	107324	56.1	0	0	874.9
1995	6561.2	0	0	0	113885	58.9	0	0	933.8
1996	6889.2	0	0	0	120775	61.9	0	0	995.7
1997	7233.7	0	0	0	128008	65.0	0	0	1060.7
1998	7595.4	0	0	0	135572	68.2	0	0	1128.9
1999	7975.1	0	0	0	143452	71.6	0	0	1200.6
2000	8373.9	0	0	0	151627	75.2	0	0	1275.8
2001	8792.6	0	0	0	159876	79.0	0	0	1354.8
2002	9232.2	0	0	0	167635	82.9	0	0	1437.7
2003	9693.8	0	0	0	171720	87.1	0	0	1524.8
2004	10178.5	0	0	0	168732	91.4	0	0	1616.3
2005	10687.4	0	0	0	155237	96.0	0	0	1712.3
2006	11221.8	0	0	0	136734	100.8	0	0	1813.1
2007	11782.9	0	0	0	117263	105.9	0	0	1919.0

TABLE V.5

AN IMPLEMENTATION PROGRAM FOR COGENERATION USING INDUSTRIAL BOILERS WITH MAXIMUM STEAM DEMANDS LESS THAN 100,000 lbs/hr

YEAR	CAPITAL, OPERATING, MAINTENANCE AND FUEL COSTS (1977 dollars x 10^3)					GENERATING CAPACITY (mw)			
	COC_1	COC_2	COC_3	COC_4	TOTAL ANNUAL COSTS	CAP_1	CAP_2	CAP_3	TOTAL AVAILABLE CAPACITY
1978	0	0	0	22.5	23	0	0	0	0
1979	0	0	0	47.3	70	0	0	0	0
1980	0	0	0	74.5	144	0	0	0	0
1981	0	0	0	104.3	248	0	0	0	0
1982	734.5	0	301.0	82.1	1366	5.2	0	5.0	10.2
1983	1542.5	0	533.6	57.5	3500	10.9	0	8.9	30.3
1984	2429.4	1926.1	444.4	30.2	8330	17.1	10.7	7.4	65.3
1985	3401.1	5962.6	0	0	17694	24.0	33.2	0	122.5
1986	3571.2	8208.3	0	0	29473	25.2	45.7	0	193.4
1987	3749.8	4239.7	0	0	37462	26.4	23.6	0	243.5
1988	3937.2	0	0	0	41400	27.8	0	0	271.2
1989	4134.1	0	0	0	45534	29.1	0	0	300.4
1990	4340.8	0	0	0	49875	30.6	0	0	331.0
1991	4557.8	0	0	0	54432	32.1	0	0	363.1
1992	4785.7	0	0	0	59218	33.7	0	0	396.8
1993	5025.0	0	0	0	64243	35.4	0	0	432.3
1994	5276.3	0	0	0	69519	37.2	0	0	469.5
1995	5540.1	0	0	0	75059	39.1	0	0	508.5
1996	5817.1	0	0	0	80876	41.0	0	0	549.5
1997	6108.0	0	0	0	86984	43.1	0	0	592.6
1998	6413.3	0	0	0	93375	45.2	0	0	637.8
1999	6734.0	0	0	0	100039	47.5	0	0	685.3
2000	7070.7	0	0	0	106965	49.8	0	0	735.1
2001	7424.3	0	0	0	114140	52.3	0	0	787.4
2002	7795.5	0	0	0	120937	55.0	0	0	842.4
2003	8185.2	0	0	0	124110	57.7	0	0	900.1
2004	8594.5	0	0	0	122410	60.6	0	0	960.7
2005	9024.2	0	0	0	114423	63.6	0	0	1024.3
2006	9475.4	0	0	0	106888	66.8	0	0	1091.1
2007	9949.2	0	0	0	95414	70.1	0	0	1161.2

TABLE V.6

AN IMPLEMENTATION PROGRAM FOR COGENERATION

YEAR	TOTAL ANNUAL COSTS ($M 1977)	TOTAL CAPACITY (mw)
1978	.1	0
1979	.3	0
1980	.7	0
1981	3.1	18
1982	12.0	99
1983	32.3	273
1984	71.9	586
1985	131.9	1084
1986	186.7	1464
1987	206.2	1605
1988	224.3	1762
1989	243.1	1927
1990	262.8	2100
1991	283.6	2282
1992	305.8	2473
1993	328.3	2613
1994	352.3	2884
1995	377.5	3105
1996	404.0	3337
1997	431.8	3581
1998	460.9	3837
1999	491.2	4106
2000	522.7	4388
2001	554.7	4684
2002	585.0	4995
2003	605.9	5322
2004	604.3	5615
2005	570.2	6025
2006	511.4	6403
2007	438.5	6800

generating station of equivalent capacity[5]. However, Leighton and Kidd make no economic comparison of cogeneration with nuclear stations, and it is this which is more appropriate for the present study since it is expected by Ontario Hydro that future fossil-fuelled stations will only be used to supply peak power, whereas cogeneration represents a source of base load power given the projected capacity factor of 80%[6].

In attempting such a cost comparison, a complicating factor is that in table V.6. cogeneration is being introduced over a 30 year period and it is not easy to compare this option with that of two or three generating stations which are brought on within the space of about 3 years. Associated with this is the possibility that the expected lifetimes of the equipment may be significantly different so that replacement costs would have to be included. However, this does not seem to be a problem. Ontario Hydro uses a nominal lifetime for a CANDU plant of 30 years (the useful lifetime may exceed this)[7]. This may be compared with the results of a U.S. survey of large industrial boilers with potential for cogeneration which found an average age of boilers of 20.7 years with an estimated average remaining life of 18.1 years[8], giving a total lifetime of nearly 40 years. In both cases, and with large fossil fuel stations as well, it is the life of the steam generating facilities, i.e. the reactors (nuclear) and boilers (cogeneration and large fossil fuelled stations) which is the limiting factor, rather than

the life of the generators, which in any case is likely to be similar for the various technologies. Therefore, it is reasonable to assume that the three systems of providing electric power - nuclear, large fossil-fuelled stations and cogeneration - have the same lifetimes.

Given the assumption of equivalent lifetimes, the economic costs of cogeneration and a CANDU station may be compared by taking account only of cogeneration capacity equal to the 2064 mw of the CANDU station. According to table V.6. this amount of capacity could be in place by 1990.

In order to make the economic comparison on equal terms it is necessary to compute the costs of each system on the assumption that they produce the same amount of energy. This means that even though the introduction of cogeneration, as described in table V.6.,would make it possible for some electricity to be generated ahead of the possible output from E15, it would penalize the cogeneration option unduly to include the costs of producing this energy. Indeed, it could be counted as an advantage to have extra capacity available sooner with cogeneration than is possible with the nuclear plant, but this is not taken into account in the economic analysis which follows. In addition, although cogeneration is expected to operate at an 80% capacity factor, some 5% greater than that for the nuclear station, for the cost comparison both systems are assumed to operate at a 75% capacity factor.

TABLE V. 7

COMPARATIVE COSTS OF A 4 x 516 mw NUCLEAR STATION (E.15) AND 2064 mw OF COGENERATION CAPACITY (1977$)

YEAR	ANNUAL COST[1] NUCLEAR ($m)	ANNUAL COST[2] COGENERATION ($m)	COST OF COGENERATION MINUS COST OF NUCLEAR ($m)
1980	3.1	0	-3.1
1981	56.1	5.8	-50.3
1982	100.2	28.3	-71.9
1983	143.8	73.3	-70.5
1984	212.2	157.0	-55.2
1985	322.4	239.1	-83.3
1986	331.6	201.0	-130.6
1987	257.8	103.1	-155.1
1988	159.7	101.2	-59.3
1989	68.0	174.5	107.0
1990	42.3	154.7	98.6
1991 to 2020	42.3	140.9	98.6

1. Table III.2 current dollar values changed to constant 1977 dollars by using Ontario Hydro's <u>Forecasting Series</u> November 1976 (25), for nuclear including heavy water, fuel, operations and maintenance.

2. Cost data from Chapter III. No specific adjustment made for expected increases in the price of fossil fuels relative to the general price level, which is broadly consistent with Ontario Hydro's November 1976 <u>Forecasting Series</u> (25), since the G.N.P. deflator is forecasted to rise more rapidly than the price of coal between 1977 and 1985, but less rapidly than the price of oil. Capital costs are assumed to be fully paid in the year in which the equipment is installed. Operating, maintenance and fuel costs are based on the assumption that cogeneration produces as much energy as would be obtained from the nuclear plant (see table III.2).

Table V.7 shows the estimated annual costs in constant 1977 dollars, associated with E15 and cogeneration. The fourth column of the table shows the difference in the annual costs of cogeneration and a nuclear plant, each capable of producing the same amount of energy over a 30 year period. It is apparent that the capital costs of cogeneration are considerably lower than those for the nuclear plant, but the operating and fuel costs are much higher. One way of evaluating the stream of cost differences shown in the table is to compute its present value i.e. the sum of money which, if available in 1977 (the base year) would have the same value as the 43 year stream of savings and expenses[9].

The results of such a present value computation are shown in table V.8.

TABLE V.8

THE PRESENT VALUE (1977) OF THE COST DIFFERENCES OF COGENERATION AND A NUCLEAR PLANT

DISCOUNT RATE	PRESENT VALUE ($m) OF COGENERATION COSTS MINUS NUCLEAR COSTS
5%	400
7%	155
10%	-21

Table V.8 shows that with a discount rate of 7% the costs of cogeneration exceed that of nuclear power by the equivalent of $155m.

The present value of the cost differences rises to $400m with a discount rate of 5%. However, a discount rate of 10% leads to the result that cogeneration is cheaper than a nuclear plant by an amount equivalent to $21m.

It is clear from table V.8 that the cost comparison of cogeneration and nuclear power is ambiguous as it depends on the value of the discount rate. Several schools of thought exist as to the appropriate discount rate. Although nothing will be said here about the merits of each position, it is worth noting that the Federal Treasury Board recommends a rate of 10% in benefit-cost studies, combined with a sensitivity analysis using rates of 5% and 15%[10].

For the purposes of the present study, it is sufficient to conclude that the costs of cogeneration are close enough to those of the nuclear alternative for cogeneration to merit inclusion in a package of measures capable of reducing the requirement for the large generating stations currently proposed for Ontario.

3. INCREASED INSULATION OF RESIDENTIAL BUILDINGS

On the basis of the information described in the previous chapters, increased insulation of residential buildings seems

to offer the most well documented, reliable and cost effective means of reducing the demand for electricity without sacrificing any of its services.

Table II.5 displays estimates of electricity that will be used for space heating in the absence of increased levels of insulation. Table IV.10 shows the estimated savings from increased insulation for various types of housing. Table IV.11 shows the estimated costs of insulation per unit of housing.

In order to estimate the total electrical energy savings from increased insulation the following assumptions about implementation and housing stock were used:

i) Starting in 1979, 10% of existing units per year would be insulated to the levels specified in Chapter IV. The housing stock in that year, assuming a small change from the situation in 1974, will be 70% single family dwellings, and 30% apartments[11]. Applying these percentages to the percentage savings to existing units reported in table IV.10 gives a weighted percent saving from improved insulation to the existing housing stock of 22%[12]. This degree of savings is phased in over the 10 year period, giving an incremental saving per year of 2.2%.

ii) It is assumed that all of the increased use of electricity for space heating after 1978 is due

to the use of electricity for space heating in new residential buildings. Estimates by the Ontario Ministry of Energy suggest the mix of new apartments and single family dwellings in Ontario shown in table V.9.

By using the projected mix of dwelling units shown in table V.9 with the estimated savings per unit in electrical heating demand shown in table IV.10 for new apartments and single family dwellings, it is possible to estimate the total energy savings[13]. These estimated savings, including the savings from reinsulating the existing housing stock, are shown in the first column of table V.10.

It should be noted that the methodology described above does not take explicit account of the conversion of fossil fuel heated homes to electrically heated homes, even though this might be a significant component of the projected increase in electricity for space heating shown in table II.5 . However, since the savings from reinsulating non-electrically heated homes are likely to be greater than those from increased insulation in new electrically heated homes, this omission would tend to lead to an underestimate of the total estimated savings.

Column 3 of table V.10 shows the estimated savings in peak demand associated with the estimated energy savings given in column 2. These were obtained by applying a 0.4 coincident load factor[14].

TABLE V.9

PROJECTED MIX OF DWELLING UNITS

FOR THE PERIOD 1976-2007 IN ONTARIO

PERIOD	SINGLE FAMILY[1]	APARTMENT
1977 - 81	45%	55%
1982 - 86	42%	58%
1987 - 91	39%	61%
1992 - 96	37%	63%
1997 - 2001	36%	64%
2002 - 2007[2]	36%	64%

1. Includes semi-detached and row houses.

2. Not included in the Ministry of Energy's projection, assumed, in the table, to be the same as for 1997-2001.

Source: Ontario Ministry of Energy. Based on a projection of dwelling unit completions for 1960-1975 and modified to give a minimum single detached penetration rate of 12% in 2001.

TABLE V.10

ESTIMATED ENERGY AND CAPACITY SAVINGS AND
ANNUAL COSTS FOR INCREASED RESIDENTIAL INSULATION

YEAR 1	ENERGY SAVINGS (10^6 mwh) 2	CAPACITY SAVINGS mw 3	COST 1976$ ($m) 4
1979	.4	114.2	88.3
1980	.7	199.8	55.9
1981	1.2	339.0	86.1
1982	1.6	456.6	85.2
1983	1.9	536.7	61.8
1984	2.3	656.9	87.4
1985	2.8	799.1	85.3
1986	3.0	856.1	51.2
1987	3.4	970.3	69.6
1988	3.9	1113.0	105.3
1989	4.4	1255.7	100.7
1990	4.8	1369.9	88.9
1991	5.4	1541.0	125.8
1992	5.7	1626.7	62.2
1993	6.3	1797.9	124.4
1994	6.7	1912.1	83.0
1995	7.2	2054.8	103.7
1996	7.8	2226.0	124.4
1997	8.1	2311.6	61.7
1998	8.9	2340.0	165.0
1999	9.7	2768.3	165.0
2000	10.2	2911.0	103.1
2001	11.0	3139.3	165.0
2002	11.9	3396.1	185.6
2003	12.6	3595.9	144.3
2004	13.3	3795.7	144.3
2005	14.3	4081.1	206.2
2006	15.4	4395.0	226.8
2007	16.0	4566.2	123.7

Table V.10 shows in column 4 the estimated costs of increased insulation for each year. Weighted averages of the costs shown in table IV.11 were used to arrive at the estimates for the cost of increasing the level of insulation[15].

One of the most significant results from table V.10 is that the average cost of saving 1 kw generating capacity by increased insulation is $682 ($1976). (This figure is obtained by dividing the summation of the fourth column by the estimated 4566.2 mw savings reported for 2007.) In any year, the cost per kw saved will be somewhat different from this since it depends upon the extent to which old housing stock is being retrofitted and the proportion of new buildings which are apartments. However, these factors tend to cancel out over the 30 year period. Capacity savings from increasing the insulation in the existing housing stock are less expensive than the savings from increasing the level of insulation in new dwellings, and all the retrofitting is assumed to occur in the first 10 years. In the later years, an increase in the proportion of new dwellings which are apartments is projected and the capacity savings from increased insulation in new apartments are less expensive than the savings from increasing the insulation in new single family dwellings.

Given these opposing trends underlying the cost estimates, the 30 year average cost per kilowatt saved of $682 is a reasonable figure to compare with Ontario Hydro's costs of adding generating capacity. From a graph published by Ontario Hydro, the capital cost per kilowatt of a CANDU plant, in 1976 dollars,

including provision for heavy water (but excluding costs for transmission, distribution, extra reserve capacity, decommissioning, etc.) is \$825/kw for a 516 mw unit and \$750/kw for a 850 mw unit[16]. When the operation, maintenance and fuel costs associated with the CANDU plant are taken into account, it is clear that it is less costly to save a kilowatt by insulation than to produce one by building a CANDU facility.

4. A PROGRAM OF COGENERATION AND RESIDENTIAL INSULATION AS AN ALTERNATIVE TO STATIONS E15 AND E16 - A PRELIMINARY ASSESSMENT

The two previous sections have suggested that cogeneration is of a comparable cost to that of electricity generated in a nuclear plant, and that an increased level of residential insulation, which reduces the demand for electricity, is less expensive than power provided from a nuclear plant. Cogeneration and residential insulation are the two measures for which the data are most complete. At the same time, they offer significant potential for reducing Ontario's requirements for large generating stations. It is worthwhile, therefore, to consider the combined contribution that these measures could make and to compare their costs with those of the generating capacity that they could displace.

In order to make the comparison, a number of assumptions were used to the effect that each system produces the same amount of energy. As in the previous comparison between cogeneration and nuclear capacity, it is assumed that electricity is only produced by cogeneration at the same time, i.e. 1987 onwards,

as it would be available from the nuclear plants. It is recognized, however, that the increased levels of insulation in the years prior to 1989, would reduce the use of coal due to the reduction in electrical demand. The value of these coal savings was subtracted from the combined costs of the cogeneration and insulation.

Table V.11 shows estimates of the capacity that could be obtained as additional supply from cogeneration, and as reduced demand from increased residential insulation in columns 1 and 2 respectively. The total capacity from these measures is shown in column 3. For the sake of the cost comparison, only an amount of cogeneration capacity and capacity saved by insulation equivalent to E15 and two units of E16 is considered, i.e. 3764 mw.

Columns 4 and 5 show the associated costs in constant 1977 dollars, and column 6 shows estimates of the value of coal saved due to the insulation. (These estimates were based on the same information and methodology used to generate the estimates in tables V.7 and V.10.) The combined total costs are shown in column 7.

Estimates for capacity and costs for the nuclear plants are given in columns 8 and 9. Only one half of the capacity and half of the costs of E16 are included, since the implementation programs for cogeneration and insulation described earlier in this study are only capable of displacing this level of capacity by 1990. The important point is that the projected levels of cogeneration and insulation of columns

TABLE V.11

COSTS OF COGENERATION AND RESIDENTIAL INSULATION COMPARED WITH NUCLEAR STATIONS E15 AND TWO UNITS OF E16

	CAPACITY			COST (1977 $)						
YEAR	COGENERATION[1] (mw) 1	INSULATION (mw) 2	TOTAL (mw) 3	COGENERATION[2] $m 4	INSULATION[3] $m 5	SAVINGS FROM COAL[4] $m 6	TOTAL COSTS $m 7	CAPACITY (NUCLEAR) E15 (4x516mw) + E16 (2x850mw) 8	COST[5] ($1977) $m 9	COST DIFFERENCE $m (COGENERATION + INSULATION - NUCLEAR) 10
1979	0	114	114	0	92	-5	88	0	0	88
1980	0	200	200	0	59	-8	51	0	3	49
1981	18	339	357	6	90	-14	82	0	70	12
1982	99	457	556	28	89	-19	98	0	149	-51
1983	273	537	810	73	65	-22	116	0	215	-99
1984	586	657	1243	157	91	-27	221	0	319	-98
1985	1084	799	1883	239	89	-33	295	0	479	-184
1986	1464	856	2320	201	54	-35	220	0	556	-336
1987	1605	970	2575	103	74	-40	137	258	468	-331
1988	1762	1113	2875	101	110	-46	165	858	322	-157
1989	1927	1256	3183	175	106	0	281	2208	170	111
1990	2100	1370	3470	206	93	0	299	3445	79	220
1991	2223	1541	3764	190	132	0	322	3764	67	255
1992 to 2021	2223	1541	3764	152	0	0	152	3764	67	85

1. Assumes only 59 mw capacity added in 1991
2. Assumes all capital costs paid in year equipment is installed.
3. Costs from table V.10 escalated by 5% to adjust to 1977 dollars.
4. Coal savings valued at $11.8/mwh (1975 figure from Ontario Hydro <u>Generation-Technical</u> (40) escalated at 7%/assumes for 2 years.
5. Tables III.2, III.3 current dollar figures deflated using index for nuclear (including 1/2 initial fuel requirement) Ontario Hydro <u>Economic Forecasting Series</u>, November 1976 (29).

1 and 2 can substitute entirely for the 3764 mw of generating capacity represented by E15 and two units of E16.

Column 10 shows the estimates of the cost differences of cogeneration and insulation, and nuclear power in each year derived by subtracting column 9 from column 7. It is apparent that from 1979 to 1981 annual costs are greater for the cogeneration/insulation alternative than for the nuclear one. This situation is reversed for 1982-1988, after which the annual cost of adding and operating nuclear capacity becomes less than that for cogeneration and insulation.

Table V.12 shows the present value of the stream of cost differences shown in column 10,using three discount rates. At a 5% rate,cogeneration and insulation are more expensive than expanding nuclear capacity,by the equivalent of $279m in 1977. This cost difference falls to $78m at a 7% discount rate and with a rate of 10%, the nuclear option becomes more expensive by $54m.

This cost comparison suggests that in Ontario there is an alternative to the immediate expansion of nuclear capacity after Darlington G.S., which is comparable in cost. When it is considered that the costs of transmission and transformer stations,reserve capacity, decommissioning and long term waste management have been omitted from the costs of the nuclear plants, it is apparent that the alternative of cogeneration and increased levels of insulation may become attractive on economic grounds alone.

In the sections which follow, implementation programs for the other measures considered in the previous chapter are considered, culminating in a combined set of measures and an estimate of the generating capacity to which they are equivalent. Detailed cost comparisons of the sort just described for cogeneration and increased insulation are not presented due to the lack of data.

TABLE V.12

THE PRESENT VALUE (1977) OF THE COST DIFFERENCES BETWEEN COGENERATION AND INSULATION, AND NUCLEAR CAPACITY

DISCOUNT RATE	PRESENT VALUE OF COGENERATION & INSULATION COSTS MINUS NUCLEAR COSTS ($m)
5%	279
7%	78
10%	-54

5. IMPLEMENTING IMPROVEMENTS IN THE EFFICIENCY OF RESIDENTIAL APPLIANCES

Table IV.13 shows several estimates of the savings that can be obtained from more efficient residential appliances. The last row of the table gives averages of these figures and it is these which are used in this chapter to estimate the potential savings in energy and, with the use of appropriate load factors, savings in capacity. For convenience the values are repeated in table V.13.

TABLE V.13

ENERGY SAVINGS FROM IMPROVEMENTS IN THE EFFICIENCY OF RESIDENTIAL APPLIANCES

APPLIANCE	ESTIMATED SAVINGS %
Water Heaters	16
Ranges	28
Lights	30
Dryers	15
Refrigerators	43
Televisions	48
Air Conditioners	35

Some of these savings can be achieved very quickly while others will require equipment redesign and could take many years[17]. Reflecting this, the rate of implementation of the total savings for each appliance that is assumed is shown in table V.14, recognising that there could be different implementation rates for each appliance owing to variations among saturation rates and equipment lifetime.

TABLE V.14

AN IMPLEMENTATION PROGRAM FOR IMPROVEMENTS IN THE EFFICIENCY OF RESIDENTIAL APPLIANCES

YEAR	ASSUMED % OF TOTAL SAVINGS ACHIEVED IN EACH YEAR
1979	1
1980	3
1981	7
1982	15
1983	25
1984	35
1985	45
1986	55
1987	65
1988	75
1989	85
1990	93
1991	97
1992	99
1993 onwards	100

By applying the implementation rate described in table V.14 and the estimated savings of table V.13, to the projected use of electricity in the residential sector from table II.5, estimated energy savings in each year are obtained. These energy savings are shown in table V.15.

The capacity savings associated with these estimated energy savings may be obtained by applying the load factors from table IV.14 to the estimates of energy savings. Estimates of the capacity savings possible in each year from 1979 to 2007 are shown in table V.16. The table indicates that for the years 1987 to 1992, those most critical for the present study, total capacity savings increase from nearly 1400 mw in 1987 to nearly 2800 mw in 1992. This represents a very significant reduction in projected capacity requirements for those years.

6. IMPLEMENTING SOLAR HEATING IN ONTARIO

As noted in the previous chapter, the I.B.I. Group has estimated, on the basis of various assumptions, the rate at which solar energy is likely to be used in Ontario for space and water heating[18]. In a subsequent report they examined the implications of these estimates for the demand for electricity[19] and the capacity requirements of Ontario Hydro.

Two years, 2001 and 2021, provide the focus for this latter study, in which the effects on electrical demand and generating capacity of using solar energy for space heating,

TABLE V.15

ESTIMATED ENERGY SAVINGS FROM THE INCREASED EFFICIENCY OF RESIDENTIAL APPLIANCES (10^6 mwh)

YEAR	WATER HEATING	REFRIG-ERATION	COOKING	LIGHTING	TV	CLOTHES DRYING	TOTAL
1979	.014	.023	.009	.006	.004	.002	.058
1980	.045	.068	.030	.021	.011	.007	.182
1981	.114	.166	.070	.050	.030	.020	.450
1982	.259	.360	.170	.140	.080	.045	1.10
1983	.448	.600	.200	.240	.140	.080	1.70
1984	.672	.900	.410	.340	.200	.126	2.70
1985	.922	1.16	.540	.470	.350	.162	3.60
1986	1.18	1.56	.720	.630	.420	.250	4.80
1987	1.46	1.90	.870	.740	.620	.290	5.90
1988	1.75	2.30	1.000	.900	.860	.330	7.10
1989	2.09	2.60	1.14	1.20	.980	.380	8.40
1990	2.38	3.03	1.30	1.50	1.07	.450	9.70
1991	2.62	3.26	1.44	1.70	1.16	.470	10.7
1992	2.79	3.40	1.55	1.90	1.18	.520	11.3
1993	2.94	3.60	1.74	1.92	1.20	.590	12.0
1994	3.00	3.80	1.85	1.98	1.34	.600	12.6
1995	3.10	3.95	2.01	1.98	1.54	.600	13.2
1996	3.20	4.09	2.24	1.98	1.90	.600	14.0
1997	3.40	4.20	2.46	2.01	2.10	.630	14.8
1998	3.50	4.34	2.68	2.04	2.30	.630	15.5
1999	3.60	4.64	2.80	2.16	2.40	.720	16.3
2000	3.65	4.82	2.90	2.28	2.50	.720	16.8
2001	3.78	4.99	3.02	2.28	2.68	.750	17.5
2002	3.87	5.16	3.14	2.40	2.68	.750	18.0
2003	4.00	5.33	3.36	2.46	2.88	.750	18.8
2004	4.13	5.50	3.53	2.82	2.88	.840	19.7
2005	4.20	5.70	3.69	3.00	3.07	.840	20.5
2006	4.34	6.10	3.86	3.24	3.07	.840	21.5
2007	4.45	6.19	3.98	3.66	3.07	.960	22.3

TABLE V.16

ESTIMATED CAPACITY SAVINGS FROM THE INCREASED EFFICIENCY OF RESIDENTIAL APPLIANCES (mw)

YEAR	WATER HEATING	REFRIG-ERATION	COOKING	LIGHTING	TV	CLOTHES DRYING	TOTAL
1979	2	3	3	3	1	1	13
1980	6	8	10	11	3	3	41
1981	16	18	23	25	8	10	100
1982	37	40	57	70	20	23	247
1983	64	67	67	120	35	40	393
1984	96	100	137	170	50	63	614
1985	132	111	180	232	88	81	824
1986	169	173	240	315	105	126	1128
1987	209	211	290	370	155	145	1380
1988	250	256	333	450	215	165	1669
1989	299	289	380	600	245	190	2003
1990	340	337	433	750	268	225	2353
1991	374	362	480	850	290	235	2591
1992	399	378	517	950	295	260	2799
1993	420	400	580	960	300	295	2955
1994	429	422	617	990	335	300	3093
1995	443	439	670	990	385	300	3227
1996	457	454	747	990	475	300	3423
1997	486	467	820	1005	525	315	3618
1998	500	482	893	1020	575	315	3785
1999	514	516	933	1080	600	360	4003
2000	521	536	967	1140	625	360	4149
2001	540	554	1007	1140	670	375	4286
2002	553	573	1047	1200	670	375	4418
2003	571	592	1120	1230	720	375	4608
2004	590	611	1177	1410	720	420	4928
2005	600	633	1230	1500	768	420	5151
2006	620	678	1287	1620	768	420	5393
2007	635	688	1327	1830	768	480	5728

domestic hot water and residential low grade heating are estimated[20]. In the report several scenarios are developed, using high and low implementation rates, and two levels of assumed market shares of electrical heating for residential, commercial and industrial use.

Separate analyses are presented for short term and annual storage systems. For the annual storage systems all the energy savings can be directly converted to power savings during the system peak hour. Power savings from short term storage systems depend on the availability of off-peak energy. The I.B.I. study assumes that electrical back-up will be used and estimates that sufficient off-peak energy will be available. Other forms of energy could also be used as back-up.

The study estimates that the impact of solar heating on the system load factor would cause less than $\pm$ 1.5% difference by 2001, even for the high penetration scenario, with and without the use of off-peak electrical energy for back-up.

The assumptions in the I.B.I. study regarding the use of electricity for heating in 2001 differ significantly from the end use projections described in Chapter II of the present study. In order to apply the I.B.I. results, the percentage savings in electricity consumption implicit in the I.B.I. study were determined and used in conjunction with the projections of electrical consumption for heating in the three sectors (after allowing for the savings due

to increased levels of insulation and improvements in the efficiency of the industrial use of electricity).

Table V.17 shows the derivation of the percentage savings, together with the power savings and equivalent load factors[21]. The 'high' and 'low' implementation scenarios are maintained throughout the analysis until all the calculations are completed, and then an average 'medium' scenario is obtained. For the 'low' scenario, less than 1% energy savings result. The 'high' scenario shows an overall energy saving of more than 13%.

In table V.18 the percentage energy savings from table V.17 are applied to the projected use of electricity for heating, taken from Chapter II, after allowing for projected energy savings due, in particular, to increased levels of insulation. The energy savings from solar heating are shown and the last column shows the equivalent peak savings based on the load factors cited in table V.17. These savings are estimated to range from a total of 240 mw in the 'low' scenario to 3210 mw in the 'high' scenario.

To obtain an estimate for electrical savings in the years prior to 2001, the implementation rate assumed in the I.B.I. studies has been adopted. The I.B.I. studies estimate the electrical energy savings from solar heating at five yearly intervals in the period leading to 2001, for the 'low' and 'high' scenarios[22]. These savings in the years before 2001 were converted to a percentage of the savings in 2001, as estimated in the I.B.I. study, and applied to the energy

TABLE V.17

ESTIMATED ELECTRICAL ENERGY AND POWER SAVINGS IN 2001 DUE TO SOLAR HEATING IN ONTARIO

	Electricity Consumption 2001 (10^{12} Btu)		Savings in Electricity Consumption 2001 (10^{12} Btu)		Per Cent Savings 2001		Equivalent Peak Savings (10^6 Btu/hr)		Equivalent Load Factor	
	LL	HH	LL	HH	LL	HH	LL	HH	LL	HH
Residential Space	74.6	72.8	.94	9.51	1.3	13.1	395	3860	.27	.28
Domestic Water	25.4	24.0	.50	4.40	2.0	18.3	140	1170	.41	.43
Industrial Space and Low Grade Heating	49.8	49.8	0	5.83	0	11.7	0	1950	0	.34
Commercial Space	17.2	17.2	.03	1.67	.2	9.7	10	610	.34	.31
TOTAL	167.0	163.8	1.47	21.41	.9	13.1	545	7590	.31	.32

Source: I.B.I. Group, Impact of Solar Heating on Electrical Power Generation in Ontario, 1977, (19)

savings in 2001 shown in table V.18 of this study. The resulting estimates of energy savings and associated peak savings, assuming the use of off-peak electricity (or other fuel) for back-up, are shown in table V.19.

Table V.19 also shows the arithmetic average of the savings attributable to the 'low' and 'high' scenarios and it is this level of savings which is used in the present study. It should be noted that in this 'medium' scenario the savings in energy and power are projected to double every five years or less until 2001.

By a linear interpolation of the five yearly estimates of table V.19 and extrapolation to 2007, estimates of energy and power savings due to the implementation of solar heating in Ontario at a modest rate are obtained. These estimates are shown in table V.20 for the years 1977 to 2007. Of particular significance is the estimated capacity savings of 324 mw in 1987 rising to 623 mw in 1992, as a result of the implementation of solar heating.

TABLE V.18

ESTIMATED ELECTRICAL ENERGY AND POWER SAVINGS FROM SOLAR HEATING FOR THE YEAR 2001

	PROJECTED ELECTRICITY CONSUMPTION (no conservation) 10^6 mwh	PROJECTED ENERGY SAVINGS 10^6 mwh	PROJECTED ELECTRICAL CONSUMPTION (including conservation) 10^6 mwh	ENERGY SAVINGS[1] 10^6 mwh		PEAK SAVINGS[2] mw	
				LL	HH	LL	HH
Residential Space	33.3	11.0	23.3	.3	3.1	130	1260
Domestic Water	23.6	3.5	20.1	.4	3.7	110	980
Industrial Heating	24.7	2.0[4]	22.7	.0	2.7	.0	910
Commercial Space	1.9[3]	.1	1.8	.0	.2	.0	60
TOTAL:				.7	9.7	240	3210

1. Energy savings applies the per cent saving in table V.17 to the projected consumption (including conservation).

2. The equivalent mw savings figure employs the load factors from table V.17.

3. All commercial heating is added together, perhaps making this figure somewhat high since cooking is included.

4. 8% savings used throughout the industrial sector.

TABLE V.19

TOTAL PROJECTED ELECTRICAL SAVINGS FROM SOLAR ENERGY

	1981		1986		1991		1996		2001	
SCENARIO	ENERGY 10^6 mwh	PEAK mw	ENERGY 10^6 mwh	PEAK mw	ENERGY 10^6 mwh	PEAK mw	ENERGY 10^6 mwh	PEAK mw	ENERGY 10^6 mwh	PEAK mw
Low-low	-	-	<.05	10	.2	60	.4	130	.7	240
High-high	.5	160	1.5	530	3.1	1020	5.4	1780	9.7	3210
Medium[1]	.25	80	.75	270	1.65	540	2.9	955	5.2	1725

1. Average of low-low and high-high scenario.

TABLE V.20

ESTIMATES OF ELECTRICAL ENERGY AND

CAPACITY SAVINGS DUE TO SOLAR HEATING IN CANADA

YEAR	ENERGY SAVINGS (10^6 mwh)	CAPACITY SAVINGS (mw)
1977	.00	0
1978	.06	20
1979	.13	40
1980	.19	60
1981	.25	80
1982	.35	118
1983	.45	156
1984	.55	194
1985	.65	232
1986	.75	270
1987	,93	324
1988	1.11	378
1989	1.29	432
1990	1.47	486
1991	1.65	540
1992	1.90	623
1993	2.15	706
1994	2.40	789
1995	2.65	872
1996	2.90	955
1997	3.36	1109
1998	3.82	1263
1999	4.28	1417
2000	4.74	1571
2001	5.20	1725
2002	5.66	1879
2003	6.12	2033
2004	6.58	2187
2005	7.04	2341
2006	7.50	2495
2007	7.96	2649

7. IMPLEMENTING ELECTRICAL SAVINGS IN THE INDUSTRIAL SECTOR

Section 10 of Chapter IV concluded that a reduction in peak industrial demand of 8% per annum was a reasonable, if conservative, estimate of what could be saved by a more efficient use of electricity by industry.

Table II.7 in Chapter II displays the end use projection of electricity in the industrial sector. This projection is repeated in column 2 of table V.21.

In section 2 of this chapter estimates were given of the extent to which industry could generate its own electricity by means of cogeneration. If cogeneration is implemented at the rate shown in table V.16 and repeated in column 3 of table V.21, industry will increase the amount of electricity it generates itself and reduce its demand for electricity to be supplied by Ontario Hydro. Assuming an 80% capacity factor[23] the electricity from cogeneration is shown in column 4 of table V.21 and subtracted from the figures in column 2 to arrive at an estimate of the industrial demand for electricity from Ontario Hydro, given in column 5[24].

This reduced demand for electricity by the industrial sector which Ontario Hydro will be expected to provide corresponds to the capacity requirements shown in column 6, estimated with the use of a .8 load factor[25]. It is these capacity requirements which can be reduced by 8% per annum if industry

practises peak shaving and energy conservation and load shifting to the extent concluded as feasible by Ontario Hydro for 1974. The estimated capacity savings of such measures are shown in column 7 of table V.21, growing from 697 mw in 1987 to 933 mw in 1992

8. IMPLEMENTING ELECTRICAL SAVINGS IN THE COMMERCIAL SECTOR

Table IV.17 repeated below, shows the estimated potential energy savings in various uses of electricity in the commercial sector.

TABLE IV.17

POTENTIAL ANNUAL ELECTRICAL ENERGY SAVINGS IN THE COMMERCIAL SECTOR

USE	POTENTIAL SAVING
Lighting	40%
Pumps and Fans	15%
Service Motors	7%
Resistance Loads	7%

The same rate of implementation as was assumed for the residential sector (see table V.14) is also assumed to apply here to take into account the fact that some of these savings will take several years to implement.

TABLE V.21

ESTIMATED CAPACITY SAVINGS DUE TO ELECTRICAL ENERGY MANAGEMENT IN THE INDUSTRIAL SECTOR

YEAR 1	INDUSTRIAL USE OF ELECTRICAL ENERGY 10^6 mwh 2	COGENERATION CAPACITY mw 3	ELECTRICAL ENERGY FROM COGENERATION 10^6 mwh 4	INDUSTRIAL DEMAND FOR ELECTRICITY FROM ONTARIO HYDRO 10^6 mwh 5	CAPACITY REQUIREMENTS OF ONTARIO HYDRO BEFORE SAVINGS mw 6	CAPACITY SAVINGS mw 7
1979	43.2	0	0	43.2	6164	493
1980	46.3	0	0	46.3	6607	529
1981	49.5	18	.1	49.4	7049	564
1982	53.4	99	.7	52.7	7520	602
1983	56.5	273	1.9	54.6	7791	623
1984	61.2	586	4.1	57.1	8148	652
1985	64.4	1084	7.6	56.8	8105	648
1986	69.1	1464	10.3	58.8	8390	671
1987	72.3	1605	11.2	61.1	8719	697
1988	78.5	1762	12.3	66.2	9446	756
1989	83.3	1927	13.5	69.8	9960	797
1990	88.0	2100	14.7	73.3	10459	837
1991	94.3	2282	16.0	78.3	11173	894
1992	99.0	2473	17.3	81.7	11658	933
1993	106.8	2613	18.3	88.5	12628	1010
1994	113.1	2884	20.2	92.9	13256	1061
1995	119.4	3105	21.8	97.6	13927	1114
1996	127.3	3337	23.4	103.9	14826	1186
1997	135.1	3581	25.1	110.0	15696	1256
1998	143.0	3837	26.9	116.1	16567	1325
1999	150.8	4106	28.8	122.0	17409	1393
2000	160.3	4388	30.8	129.5	18479	1478
2001	169.7	4684	32.8	136.9	19535	1563
2002	180.7	4995	35.0	145.7	20701	1663
2003	191.7	5322	37.3	154.4	22032	1763
2004	202.7	5615	39.3	163.4	23316	1865
2005	215.3	6025	42.2	173.1	24700	1976
2006	232.6	6403	44.9	187.7	26784	2143
2007	249.9	6800	47.7	202.2	28853	2308

By applying the implementation rate described in table V.14 and the estimated energy savings of table IV.17 to the projected use of electricity in the commercial sector from table II.6, estimated energy savings in each year are obtained. These energy savings are shown in table V.22[26].

The capacity savings made possible by these estimated energy savings were estimated by using the load factors shown in table IV.15[27]. The estimated capacity savings are given in table V.23 and show potential savings ranging from 1080 mw in 1987 to 2250 mw in 1992.

9. IMPLEMENTING LOAD MANAGEMENT IN ONTARIO

Virtually all of the savings in capacity that have been estimated in previous sections of the report have been based on the assumption that the load factor for each use of electricity will remain unchanged over the next 30 years. In other words, the proportional savings in the peak demand for electricity have been assumed equal to the proportional savings in the average demand for electricity, for each use. The only exception to this assumption is savings in the industrial sector which included Ontario Hydro's estimates of the potential for peak shifting in that sector.

Section 12 of Chapter IV drew attention to the fact that the assumed system load factor for Ontario Hydro's system was low by international standards and that other utilities have succeeded in raising their system load factors by a greater use of load management practices. It was concluded that a

TABLE V.22

ESTIMATED ENERGY SAVINGS BY END USE
IN THE COMMERCIAL SECTOR (10^6 mwh)

YEAR	MOTORS	LIGHTING	HEATING	TOTAL
1979	.02	.04	.001	.06
1980	.05	.13	.004	.2
1981	.13	.33	.01	.5
1982	.29	.76	.03	1.1
1983	.53	1.4	.05	2.0
1984	.80	2.0	.07	2.9
1985	1.1	2.7	.09	3.9
1986	1.5	3.6	.12	5.2
1987	1.8	4.4	.15	6.3
1988	2.3	5.3	.18	7.8
1989	2.7	6.4	.23	9.3
1990	3.1	7.5	.26	10.9
1991	3.5	7.8	.29	11.6
1992	3.9	9.0	.31	13.2
1993	4.1	9.6	.34	14.0
1994	4.3	10.1	.36	14.7
1995	4.6	10.6	.38	15.6
1996	4.8	11.4	.40	16.6
1997	5.1	12.0	.43	17.5
1998	5.3	12.6	.45	18.4
1999	5.6	13.2	.48	19.3
2000	5.9	14.0	.50	20.4
2001	6.2	14.8	.53	21.5
2002	6.6	15.6	.57	22.8
2003	7.0	16.4	.59	24.0
2004	7.4	17.4	.62	25.4
2005	7.8	18.2	.67	26.7
2006	8.2	19.2	.70	28.1
2007	8.7	20.1	.75	29.6

TABLE V.23

ESTIMATED CAPACITY SAVINGS FROM THE INCREASED EFFICIENCY OF THE USE OF ELECTRICITY IN THE COMMERCIAL SECTOR

(mw)

YEAR	MOTORS	LIGHTING	HEATING	TOTAL
1979	3	6	1	10
1980	8	23	1	32
1981	22	55	3	80
1982	48	127	10	185
1983	88	233	17	338
1984	133	333	23	490
1985	183	450	30	663
1986	250	600	40	890
1987	300	732	50	1082
1988	383	883	60	1327
1989	450	1067	67	1584
1990	517	1250	84	1851
1991	583	1300	97	1980
1992	650	1497	103	2250
1993	678	1600	113	2392
1994	708	1683	120	2512
1995	767	1767	127	2660
1996	800	1900	133	2833
1997	850	1993	143	2986
1998	883	2100	150	3133
1999	933	2200	160	3293
2000	983	2333	167	3483
2001	1033	2467	177	3677
2002	1100	2600	190	3890
2003	1167	2733	197	4097
2004	1225	2900	207	4327
2005	1300	3033	223	4557
2006	1367	3200	233	4800
2007	1450	3350	250	5050

70% load factor is achievable in Ontario. In comparison with the load factor of 65.8% that Ontario Hydro assumes will prevail in the future this would result in considerable capacity savings.

It would not be legitimate to merely compute the capacity savings for each year implied by an increase in the load factor from 65.8% to 70% and add this to the capacity savings estimated for the other measures that have been considered. This is because the implementation of these measures may effect the system load factor (even though the load factor for each end use is presumed to remain unchanged). To account for this, the aggregated energy savings and capacity savings for each year resulting from all the measures were computed, so that the new system load factor, before load management, could be calculated. The load factor for each year from 1979-2007, following the implementation of all the measures already discussed, is shown in table V.24.

Table V.24 shows that even without deliberate attempts to manage the system load, implementation of the various measures described earlier will raise the load factor steadily from 66.9% in 1979 to 69.3% in 2007. Given the target load factor of 70%, assumed achievable with load management, an implementation rate of load management practices that raises the system load factor to 70% by 1990 was used to estimate the capacity savings possible with load management. Table V.25 shows the increase in the load factor assumed for each year, so that a value of 70% is

TABLE V.24

SYSTEM LOAD FACTOR WITH THE IMPLEMENTATION OF VARIOUS ENERGY MEASURES[1]

YEAR	LOAD FACTOR (%)[2]
1979	66.9
1980	68.9
1981	66.9
1982	67.3
1983	67.4
1984	67.7
1985	67.5
1986	67.5
1987	67.8
1988	68.0
1989	68.2
1990	68.4
1991	68.6
1992	68.8
1993	68.8
1994	68.9
1995	68.8
1996	68.9
1997	68.9
1998	68.7
1999	69.1
2000	69.1
2001	69.1
2002	69.1
2003	69.1
2004	69.2
2005	69.2
2006	69.3
2007	69.3

1. See previous sections of this chapter.

2. The load factors were calculated using the formula

$$LF^t = \frac{E_f^t - E_s^t}{8760} \cdot \frac{1}{M_f^t - M_s^t}$$

Continued........

where:

LF^t = Load factor in year t

E_f^t = Ontario Hydro's energy forecast for year t

E_s^t = Estimated energy savings for year t (see table V.28)

M_f^t = Ontario Hydro's peak forecast for year t

M_s^t = Estimated peak savings for year t (see table V.29)

TABLE V.25

ESTIMATED CAPACITY SAVINGS FROM LOAD MANAGEMENT

YEAR	ASSUMED INCREASE IN SYSTEM LOAD FACTOR (%)	CAPACITY SAVINGS mW
1979	0.0	0
1980	0.0	0
1981	0.0	0
1982	0.0	0
1983	0.2	57
1984	0.4	127
1985	0.6	210
1986	0.8	281
1987	1.0	370
1988	1.2	447
1989	1.4	525
1990	1.6	641
1991	1.4	589
1992	1.2	560
1993	1.2	567
1994	1.1	567
1995	1.2	658
1996	1.1	649
1997	1.1	664
1998	1.3	828
1999	0.9	617
2000	0.9	629
2001	0.9	664
2002	0.9	684
2003	0.9	723
2004	0.8	681
2005	0.7	682
2006	0.7	698
2007	0.7	714

reached in 1990 and sustained until 2007. The table also shows the capacity savings for each year that would result from these increases in the load factor. The estimated savings rise from 57 mw in 1983 to 641 mw in 1990, decline somewhat for the next five years and then commence an upward trend for the rest of the period. The pattern of savings reflects the fact that the load factor of the system is projected to rise without load management and so the relative and, in some years, the absolute savings from load management decline once the 70% load factor is reached in 1990 and maintained thereafter.

10. THE OTHER MEASURES

In addition to the measures that have been discussed in this chapter, there are several others which were reviewed in Chapter IV. For various reasons there is little more to be said about them and so their potential role in displacing large generating stations after 1987 will be examined quite briefly.

i) Utilization of Small Hydro Sources

Section 5 of Chapter IV concluded that 70 mw of additional hydraulic capacity is economically competitive with fossil-fuelled stations and could be introduced over the next 15 years. Even though this would make a comparatively small contribution to Ontario's electrical energy system, it is worth considering as part of an overall program.

ii) Wind Generated Electricity

Wind generated electricity in Ontario is not considered capable of competing with other means of providing electricity in large quantities. Its primary role is likely to be as a substitute for diesel powered generators in remote locations.

iii) District Heating

District heating, which could play an important role in an overall energy strategy for Ontario, cannot be justified in the narrower context of the present study. The reason for this, as explained in section 13 of Chapter IV, is that district heating is likely to increase the requisite generating capacity in Ontario. However, the considerable gains in the reduced requirements for fossil fuels as a means of space heating, could well justify this increase.

iv) Interconnections

The discussion of interconnections reported the conclusion of the Select Committee of the Legislature that proper evaluation of Ontario Hydro's existing interconnections could lower Ontario Hydro's requirements for reserve capacity by at least 500 mw and perhaps by more than 1000 mw.

If this conclusion is accepted then future additions to Ontario Hydro's capacity can be reduced by these amounts.

The present study takes no position on this particular issue and only notes the possibility that Ontario Hydro's proposed expansion plan exceeds what is required to meet its own load forecast by several hundred megawatts.

11. A ROLE FOR ELECTRICITY GENERATED FROM BIOMASS

Section 3 of Chapter IV concluded that from 1985 onwards, there will be sufficient collectable biomass to support a generating capacity of 750 mw at a 70% capacity factor. The cost figures cited in section 3 can be used to evaluate the cost competitiveness of generating electricity from this source.

In this section the costs of a single 750 mw coal fired unit are compared with five 150 mw units using biomass as fuel. The estimated costs of each are shown in table V.26

TABLE V.26

COMPARATIVE COSTS OF GENERATING ELECTRICITY FROM BIOMASS IN 150 MW PLANTS, AND FROM COAL IN A 750 MW UNIT

COSTS (1985 dollars)	BIOMASS[1]	COAL[2]
Capital $/kw	1,200	550
Operation & Maintenance $/kw	20	10
Fuel $/kwh	0.03	0.17

1. Biomass - see section 3, Chapter IV.
2. Coal - Ontario Hydro, Generation-Technical, (40) Escalation factors from Forecasting Series, November 1976 used to adjust fuel costs.

The costs in table V.26 provide the basis for a present value comparison of the two options. Table V.27 shows the results of such a comparison for three discount rates and for three capacity factors.

TABLE V.27

PRESENT VALUE OF THE COST DIFFERENCES OF GENERATING ELECTRICITY FROM 5 X 150 MW BIOMASS-FUELLED UNITS AND 1X 750 MW COAL-FIRED UNITS ($/M 1985)

	CAPACITY FACTOR		
DISCOUNT RATE	70%	50%	30%
5%	$387m	$104m	-$276m
7%	$219m	-$10m	-$318m
10%	$49m	-$125m	-$359m

Table V.27 shows the tremendous sensitivity of the results to the size of the discount rate and the assumed lifetime capacity factor. Regarding the capacity factor, it is worth noting that a lower figure is probably more appropriate in the Ontario context since Ontario Hydro proposes to use additional coal fired facilities primarily for peak power[(28)]. However, Ontario Hydro has indicated the following lifetime capacity factors for its proposed coal fired plants[(29)]:

1985 - 2000	:	65% declining to 45%
2000 onwards	:	45% declining to 30%

In light of these ambiguous results and given the uncertain nature of the cost estimates which underlie them, it cannot be concluded unequivocably, that small scale biomass-fuelled plants are cost competitive with a large scale coal fired unit. The J.P.R. study [30] which also compared biomass and coal plants, concluded that, for Vermont at least, coal was cheaper than wood. (Solid waste as a fuel was not considered.) It noted, however, that there are several other reasons, such as job creation and increased reliance on indigenous renewable resources, which could justify the construction of wood-fuelled plants.

The J.P.R. study concluded that "the use of wood as a fuel for electrical generation in Vermont should be vigorously pursued" [30], a recommendation fully supported by the Mitre study [31].

Some attention should also be given to the arguments that smaller stations might be more suitable for incorporation within district heating schemes. Moreover, they require less reserve capacity than large stations of equivalent overall capacity, and can probably be built with shorter lead times.

Bearing in mind all these considerations, it is not unreasonable to assume that five 150 mw capacity stations using biomass as fuel could provide a viable alternative to one 750 mw coal fired unit, and could be in service by 1992.

12. CONCLUSION

In the previous sections of this chapter, implementation programs for each of the measures were considered taking full account of any interrelationships. The energy and capacity savings resulting from these measures can therefore be aggregated to arrive at an overall assessment of possible savings in each year to 2007.

Table V.28 shows the estimated energy savings in each year. The combined savings from cogeneration and residential insulation are shown in column 3, and a grand total of all savings for each year is shown in column 8.

This last column indicates that, if all the measures considered in the table are implemented, there will be a reduction in the annual demand for energy to be supplied by Ontario Hydro which rises from 2.4×10^6 mwh in 1979 to 131.7×10^6 mwh in 2007.

Table V.29 shows the capacity savings which correspond to the energy savings of table V.28. A sub-total for the capacity savings resulting from cogeneration and increased residential insulation is given in column 3, and a grand total of all savings is given in column 9.

Column 9 shows that Ontario Hydro's expansion program could be reduced by an estimated 671 mw in 1979 and by as much as 27,807 mw in 2007 if all the measures were implemented.

TABLE V.28

A SUMMARY OF THE ANNUAL ENERGY SAVINGS DUE TO ALL THE MEASURES

(10^6 mwh)

YEAR	COGENERATION 1	RESIDENTIAL INSULATION 2	SUB-TOTAL (1 & 2) 3	RESIDENTIAL APPLIANCES 4	SOLAR HEATING 5	EFFICIENCY IN COMMERCIAL SECTOR 6	EFFICIENCY IN INDUSTRIAL SECTOR 7	TOTAL
1979	0	.4	.4	.1	.1	.1	1.7	2.4
1980	0	.7	.7	.2	.2	.2	1.9	3.2
1981	.1	1.2	1.3	.5	.3	.5	2.0	4.6
1982	.7	1.6	2.3	1.1	.4	1.1	2.1	7.0
1983	1.9	1.9	3.8	1.7	.5	2.0	2.2	10.2
1984	4.1	2.3	6.4	2.7	.6	2.9	2.3	14.9
1985	7.6	2.8	10.4	3.6	.7	3.9	2.3	20.9
1986	10.3	3.0	13.3	4.8	.8	5.2	2.4	26.5
1987	11.2	3.4	14.6	5.9	.9	6.3	2.4	30.1
1988	12.3	3.9	16.2	7.1	1.1	7.8	2.6	34.8
1989	13.5	4.4	17.9	8.4	1.3	9.3	2.8	39.7
1990	14.7	4.8	19.5	9.7	1.5	10.9	2.9	44.5
1991	16.0	5.4	21.4	10.7	1.7	11.6	3.1	48.5
1992	17.3	5.7	23.0	11.3	1.9	13.2	3.3	52.7
1993	18.3	6.3	24.6	12.0	2.2	14.0	3.6	56.4
1994	20.2	6.7	26.9	12.6	2.4	14.7	3.7	60.3
1995	21.8	7.2	29.0	13.2	2.7	15.6	3.9	64.4
1996	23.4	7.8	31.2	14.0	2.9	16.6	4.2	68.9
1997	25.1	8.1	33.2	14.8	3.4	17.5	4.4	73.3
1998	26.9	8.9	35.8	15.5	3.8	18.4	4.6	78.1
1999	28.8	9.7	38.5	16.3	4.3	19.3	4.9	83.3
2000	30.8	10.2	41.0	16.8	4.7	20.4	5.2	88.1
2001	32.8	11.0	43.8	17.5	5.2	21.5	5.5	93.5
2002	35.0	11.9	46.9	18.0	5.7	22.8	5.8	99.2
2003	37.3	12.6	49.9	18.8	6.1	24.0	6.2	105.0
2004	39.3	13.3	52.6	19.7	6.6	25.4	6.5	110.8
2005	42.2	14.3	56.5	20.5	7.0	26.7	6.9	117.6
2006	44.9	15.4	60.3	21.5	7.5	28.1	7.5	124.9
2007	47.7	16.0	63.7	22.3	8.0	29.6	8.1	131.7

TABLE V.29

A SUMMARY OF THE ANNUAL CAPACITY SAVINGS DUE TO ALL MEASURES

(mw)

YEAR	COGENERATION 1	RESIDENTIAL INSULATION 2	SUB-TOTAL (1 & 2) 3	RESIDENTIAL APPLIANCES 4	SOLAR HEATING 5	EFFICIENCY IN COMMERCIAL SECTOR 6	EFFICIENCY IN INDUSTRIAL SECTOR 7	LOAD MANAGEMENT 8	TOTAL 9
1979	0	114	114	13	40	10	493	0	671
1980	0	200	200	41	60	32	529	0	862
1981	18	339	357	100	80	80	564	0	1181
1982	99	457	556	247	118	185	602	0	1708
1983	273	537	810	393	156	338	623	57	2377
1984	586	657	1243	616	194	490	652	127	3322
1985	1084	799	1883	824	232	663	648	210	4460
1986	1464	856	2320	1128	270	890	671	281	5560
1987	1605	970	2575	1380	324	1082	697	370	6428
1988	1762	1113	2875	1669	378	1327	756	447	7452
1989	1927	1256	3183	2003	432	1584	797	525	8524
1990	2100	1370	3470	2353	486	1851	837	641	9638
1991	2282	1541	3823	2591	540	1980	894	589	10417
1992	2473	1627	4100	2799	623	2250	933	560	11265
1993	2613	1798	4411	2955	706	2392	1010	567	12041
1994	2884	1912	4796	3093	789	2512	1061	567	12848
1995	3105	2055	5160	3227	872	2660	1114	658	13691
1996	3337	2226	5563	3423	955	2833	1186	649	14609
1997	3581	2312	5893	3618	1109	2986	1256	664	15526
1998	3837	2340	6177	3785	1263	3133	1325	828	16511
1999	4106	2768	6874	4003	1417	3293	1393	617	17597
2000	4388	2911	7299	4149	1571	3483	1478	629	18609
2001	4684	3139	7823	4286	1725	3677	1563	664	19738
2002	4995	3396	8391	4418	1879	3890	1663	684	20925
2003	5322	3596	8918	4608	2033	4097	1763	723	22142
2004	5615	3796	9411	4928	2187	4327	1865	681	23399
2005	6025	4081	10106	5151	2341	4557	1976	682	24813
2006	6403	4395	10798	5393	2495	4800	2143	698	26327
2007	6800	4566	11366	5728	2649	5050	2308	714	27807

In addition to this, there is 750 mw that could be available from small generating stations utilizing biomass as fuel, and 70 mw from small hydro sources. This extra capacity of more than 800 mw can be added to the last column of table V.29 from 1990 onwards, allowing time for planning and construction of the facilities.

Table V.29 shows that between 1987 and 1993 the capacity savings rise from an estimated 6,428 mw to 12,041 mw. Comparing this with the 11,464 mw of the first four stations proposed by Ontario Hydro after Darlington G.S., it appears that all four stations could be dispensed with if the alternative measures are implemented. However, this does not necessarily mean that no new large generating stations will be required until after 1993 since there is some overlap between the timing of the last units of E17 and E18 and the timing of the first units of the next three stations: E19, E20 and E21. In order to clearly answer the question as to how long the introduction of new large generating facilities could be postponed after Darlington G.S., it is necessary to examine Ontario Hydro's expansion plans in more detail.

Table V.30, column 2, shows for the years 1987 to 2007, the cumulative amount of capacity Ontario Hydro proposes to install (in the East System[31]) after Darlington G.S. Column 3 of the table shows the estimated capacity savings that would reduce the requirement for additional capacity from Ontario Hydro. The fourth column shows the difference between Ontario Hydro's proposed expansion program and these capacity savings. In 1987, there would be a surplus

TABLE V.30

A COMPARISON OF ONTARIO HYDRO'S CAPACITY EXPANSION PROGRAM AND THE ESTIMATED CAPACITY SAVINGS

YEAR	ONTARIO HYDRO'S (EAST SYSTEM)[1] (mw)	ESTIMATED CAPACITY SAVINGS[2] (mw)	NET CAPACITY REQUIREMENTS FOR ONTARIO HYDRO (mw)
1987	516	6428	-5912
1988	1882	7452	-5570
1989	5264	8524	-3260
1990	8464	9628	-1164
1991	11664	10417	1247
1992	14464	11265	3199
1993	18014	12041	5973
1994	21164	12848	8316
1995	26564	13691	12873
1996	31664	14609	17055
1997	36764	15526	21238
1998	41414	16511	24903
1999	46514	17597	28917
2000	51614	18609	33005
2001	57014	19738	37276
2002	65664	20925	44739
2003	71164	22142	49022
2004	78164	23399	54765
2005	85664	24813	60851
2006	95914	26327	69587
2007	104914	27807	77107

1. Ontario Hydro <u>LRF 48A</u> (Appendix B).

2. Table V.29.

capacity of nearly 6000 mw. This declines rapidly and in 1991, Ontario Hydro would be required to provide 1247 mw of new capacity. Of this amount, 750 mw could come from five 150 mw plants using biomass as a fuel and 70 mw could come from small hydro sources. As a result the capacity requirements for Ontario Hydro in that year would be minimal. In 1992 an addition of almost 2000 mw would be required. Therefore, this is the time when the next large station after Darlington G.S. would be required to satisfy Ontario Hydro's load forecast, if the measures described in this report are implemented.

Having answered the question posed in Chapter I, it is important to recognize that the purpose of asking it was not to define the ideal energy strategy for Ontario. Rather it was to provide a focus for examining the extent to which real alternatives are available in Ontario without questioning Ontario Hydro's forecast of load growth.

On the basis of the assumptions and estimates that have been detailed in this report, it appears that there are a number of alternatives of comparable cost to the proposed construction of large generating stations due to enter service in the next 10-15 years. This suggests that the ongoing debate about energy policy need not be constrained by a lack of alternatives.

FOOTNOTES

1. Leighton and Kidd, Industrial By-Product Power, 1977, (22)

2. The implementation program suggested by Leighton and Kidd only allows for the first two of these activities.

3. The values for U_2 for the largest category of maximum steam demands when applied to MSD^u give the result that 75% of the steam demands in 1977 are ultimately retrofitted for cogeneration.

4. Capital costs are amortized over 20 years at a 10% rate of interest.

5. Leighton and Kidd, p. 19-21 (22)

6. Leighton and Kidd, p. 14 (22)

7. Ontario Hydro, Generation-Technical, p. 21-67 (40)

8. R.F. Dittrich and K.D. Allon, PSE and G Cogeneration Evaluation, Report No. 36.76.12, 1977, (9)

9. The formula for the present value used in the calculations is :

$$PV = \sum_{t=3}^{42} \frac{D_t}{(1+r)t}$$

where PV is present value, Dt is the cost difference in year t and r is the discount rate. Initially t is set at 3 so that the present value calculation produces a value for 1977.

10. Treasury Board, A Guide to Benefit-Cost Analysis, 1976 (57). Note that a rate of 15% would significantly increase the cost advantage of cogeneration.

11. Ontario Hydro, Memorandum to the Board of Directors, 1976 Schedule D (33) The housing stock in 1974 was 72% single family and 28% apartments.

12. Weighted percent saving $\frac{.7(.23 \times 77.5) + .3\ (.15 \times 28.3)}{(.7 \times 77.5) + (.3 \times 28.3)} = 22.4\%$

13. The equation used is $ES_t = E_t \times (.458 - \frac{.09}{.575\ S_t})$

where ES_t = energy saved in year t, E = energy used in the absence of increased insulation, S_t = proportion of new dwellings that are single family in year t.

14. Ontario Hydro, Memorandum to the Board of Directors, Schedule C, Table 4 (32)

15. The equation used for new dwellings is $CS_t^n = 296 - \frac{66.3}{.378 + S_t}$

where CS_t^n = cost per mwh saved in year t in an average new dwelling, S_t = proportion of new dwellings that are single family in year t.

The equation used for existing dwellings is : $CS^e = (.7 \times \$950 + .3 \times \$75) = \$687.5$

where CS^e = cost per average existing unit.

This corresponds to a weighted energy saving per existing unit of 4.03 mwh, giving a cost per mwh saved in existing buildings of $170.6.

16. Ontario Hydro, Generation-Technical, Vol. 1, Fig. 2.1. 8-1 (40)

17. T.T. Woodson, "Residential Energy Use" Efficient Electricity Use, C.B. Smith (ed.)(55)

18. I.B.I. Group, Solar Heating: An Estimate of Market Penetration, 1977 (18)

19. I.B.I. Group, Impact of Solar Heating on Electrical Power Generation in Ontario, 1977 (19)

20. The possibly significant use of solar energy for commercial water heating was not considered.

21. The load factors should not be interpreted as the load factor for solar heating in the normal sense. Theoretically, if solar systems used no power at peak they would have an infinite load factor. This equivalent load factor is useful in translating solar energy savings into electrical power savings at peak. Columns 1, 2 and 4 in Table V.17 are derived from (19), Exhibit 6, Exhibit 7 and Exhibits 10 & 13 respectively by averaging values for Scenarios 1 and 2. Columns 3 and 5 are derived from the other columns.

22. I.B.I. Group, Solar Heating, 1977, Exhibit 46 (18)

23. Leighton and Kidd, Industrial By-Product Power, 1977, (22)

24. The cogeneration capacity represents additions to the installed cogeneration capacity currently in place.

25. See p. 88

26. Owing to a small error, the estimated savings for heating in the years 1997-2007 were based on estimates of electricity used for heating somewhat lower than the figures given in table II.6.

27. A weighted average of the load factor for pumps and fans, and service motors was used.

28. See p.32

29. Personal communication from Ontario Hydro.

30. J.P.R. Associates, The Feasibility of Generating Electricity in the State of Vermont, 1975 (20).

31. Mitre Corporation, Conference on Silviculture Biomass Plantations, 1977, (26).

32. Ontario Hydro, LRF 48A (Appendix B).

APPENDIX A

THE END USE OF

ELECTRICITY IN ONTARIO, 1987-2007

A QUESTIONNAIRE

Middleton Associates

Research Consultants
Energy, Resources and Environment

Dear

As we discussed, the Royal Commission on Electric Power Planning is funding a project to determine what measures could be taken in Ontario to reduce the electrical demand from Ontario Hydro sufficiently to postpone the requirement for another generating station after Darlington (as proposed in LRF 48A).

In order to accomplish this task it is necessary to forecast an end use mix that is consistent with Ontario Hydro's 1977 load forecast (No. 770214).

As a first step I have disaggregated Ontario Hydro's forecast of peak demand for 1977 to 2007 into residential, commercial and industrial end uses, using the proportions that applied in 1974. (Energy Utilization and the Role of Electricity, Ontario Hydro 1976, Tables 6-2-6 and 6-2-11.) The projections are displayed in the attached figures II, III and IV.

There are several reasons for thinking that both the sectoral split and the split among end uses within each sector will change over the next 30 years and I would greatly appreciate your opinion on this specific matter. To this end I have prepared a very brief questionnaire for you to complete and return as soon as possible. After I have received all the completed questionnaires, and if time permits, I will inform you of the average group response to each question and give you the opportunity to revise your answers in the light of the views of others.

If you require any further explanation or more information please call me at 961-5136.

Thank you for your co-operation.

Yours sincerely,

Peter A. Victor

PAV/bvs

980 Yonge Street, Suite 404, Toronto
Canada, M4W 2J9 (416) 961-5136

THE END USE OF ELECTRICITY IN ONTARIO, 1987-2007

A QUESTIONNAIRE

I PURPOSE

This questionnaire is designed to solicit the views of a few people who have considerable knowledge of energy issues, regarding the end use of the load growth that has been forecast by Ontario Hydro. A copy of the 1977 load forecast is attached.

For the purpose of the study for which this questionnaire is being used, the forecasted, aggregate load growth is accepted as given. Our specific interest is in the distribution of the forecasted load among the residential, commercial and industrial sectors, and among the various end uses within each sector. Accordingly, you are not asked to assess the accuracy of the load forecast but only to state your views on the proportion of the load that you think will be accounted for by each sector and end use. As far as possible your end use forecast should be consistent with the assumptions underlying Ontario Hydro's load forecast, even if you do not agree with these assumptions.

II BACKGROUND INFORMATION

A copy of Ontario Hydro's February 1977 forecast of "December primary peak demand" is attached (see figure I). The principle assumptions underlying this forecast are:

i) A somewhat lower rate of economic growth in the short-term than existed in the 1960's.

ii) The increasing price of electricity and appliances will tend to be offset by increasing prices and possible short-falls of competing fuels. Allowances have been made for the effect of prices upon both peak demand and energy demand.

iii) Load management (non-price) to curtail loads in peak periods has not been allowed for.

iv) The effect of the 1973 oil crisis on prices and incomes is assumed to be permanent and increasingly depressing on the economy.

v) The forecast takes account of the conservation targets established by Ontario Hydro.

vi) Beyond 1986 a decline in the growth rate of peak demands is assumed, and reflects a possible pattern of income growth consistent with today's demographic trends.

vii) During the 1990's it is recognised that the world may face a severe oil crisis. This will tend to inhibit economic growth, encourage the development of alternative energy technologies, and may lead to increased reliance on electricity.

viii) Typical weather conditions are assumed.

By applying a load factor, Ontario Hydro's forecast of peak demand has been converted into an equivalent forecast of energy demand. Figures II, III and IV display an end use forecast utilizing the percentage distribution of electricity demand among end uses that prevailed in 1974. These percentages are held constant over the 30-year period.

This particular end use forecast is intended only to provide you with a benchmark to assist you in making your own forecast.

Some historical data are provided with each question. All of these data are taken from Energy Utilization and the Role of Electricity, Ontario Hydro submission to the Royal Commission on Electric Power Planning, April 1976. For further background information, that document should be consulted.

III THE QUESTIONS

Please respond to these questions by writing percentage figures in the various tables.

Question 1

What do you think the distribution of electricity use in each market sector will be?

Sector	1966	1971	1974	1987	1997	2007
Residential	28.8	31.0	31.4			
Commercial	20.3	22.4	27.2			
Industrial	50.9	46.6	41.4			
Total	100.0	100.0	100.0			

Question 2

What do you think the distribution of electricity among end uses will be in the RESIDENTIAL sector? (See attachment)

End Use	1951	1961	1971	1974	1987	1997	2007
Misc.	8.2	5.3	5.4	7.3			
Clothes Drying	0.0	2.7	4.1	4.3			
Air Cond.	0.0	0.0	0.7	1.0			
TV	2.8	4.5	4.8	5.2			
Lighting	15.6	10.4	8.6	7.7			
Stove Cooking	13.9	12.2	11.4	10.7			
Refrigeration	6.7	9.4	14.8	13.8			
Space Heating	5.3	4.7	17.8	20.2			
Water Heating	47.5	50.8	32.4	29.8			
Total	100.0	100.0	100.0	100.0			

Question 3

What do you think the distribution of electricity among end uses will be in the COMMERCIAL sector?

End Use	1974	1987	1997	2007
Motors	51.0			
Heating	5.8			
Lighting	38.8			
Other	4.4			
Total	100.0			

Question 4

What do you think the distribution of electricity among end uses will be in the INDUSTRIAL sector?

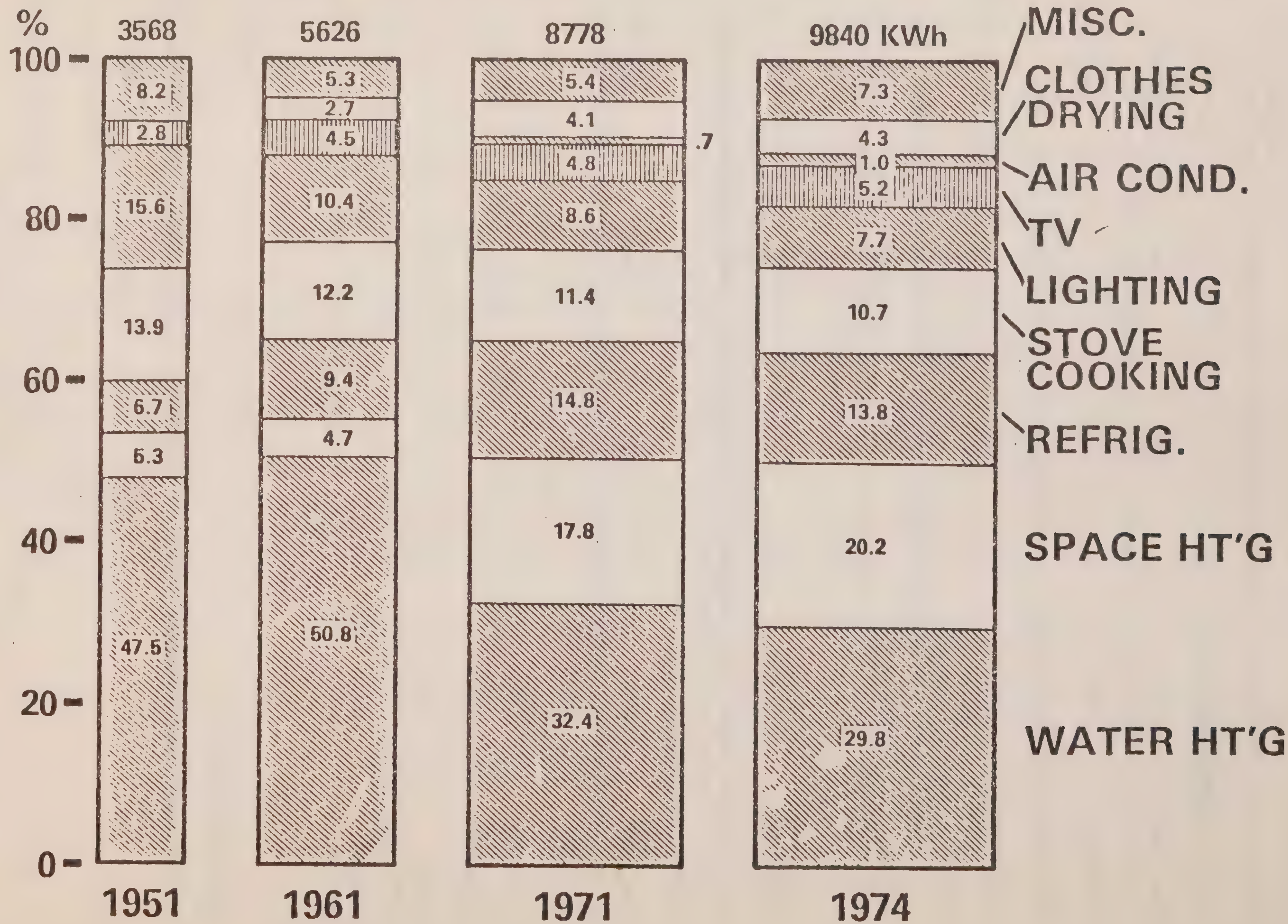
End Use	1974	1987	1997	2007
Motors	76.1			
Heating	13.7			
Lighting	10.2			
Other	0.0			
Total	100.0			

CONFIDENTIALITY

Do you wish your response to be confidential (please circle appropriately)?

YES NO

ONTARIO HYDRO
AVG. RESIDENTIAL CONSUMPTION BY END-USE



LOAD GROWTH SCENARIOS
(DECEMBER PRIMARY PEAK DEMAND)

	Forecast		
	TOTAL	ES	WS
1977	16614	15717	897
1978	17802	16880	922
1979	18954	17959	995
1980	20251	19189	1062
1981	21577	20480	1097
1982	22968	21806	1162
1983	24400	23180	1220
1984	25921	24640	1281
1985	27562	26217	1345
1986	29333	27921	1412
1987	31197	29714	1483
1988	33172	31615	1557
1989	35264	33629	1635
1990	37481	35765	1716
1991	39831	38029	1802
1992	42316	40424	1892
1993	44950	42963	1987
1994	47734	45648	2086
1995	50682	48492	2190
1996	53702	51402	2300
1997	56901	54486	2415
1998	60291	57755	2536
1999	63883	61220	2663
2000	67689	65893	2796
2001	71722	68787	2935
2002	75996	72914	3082
2003	80525	77289	3236
2004	85324	81926	3398
2005	90410	86842	3568
2006	95798	92052	3746
2007	101509	97575	3934

FIGURE 2

ONTARIO RESIDENTIAL ENERGY DEMAND PROJECTION
1977-2007

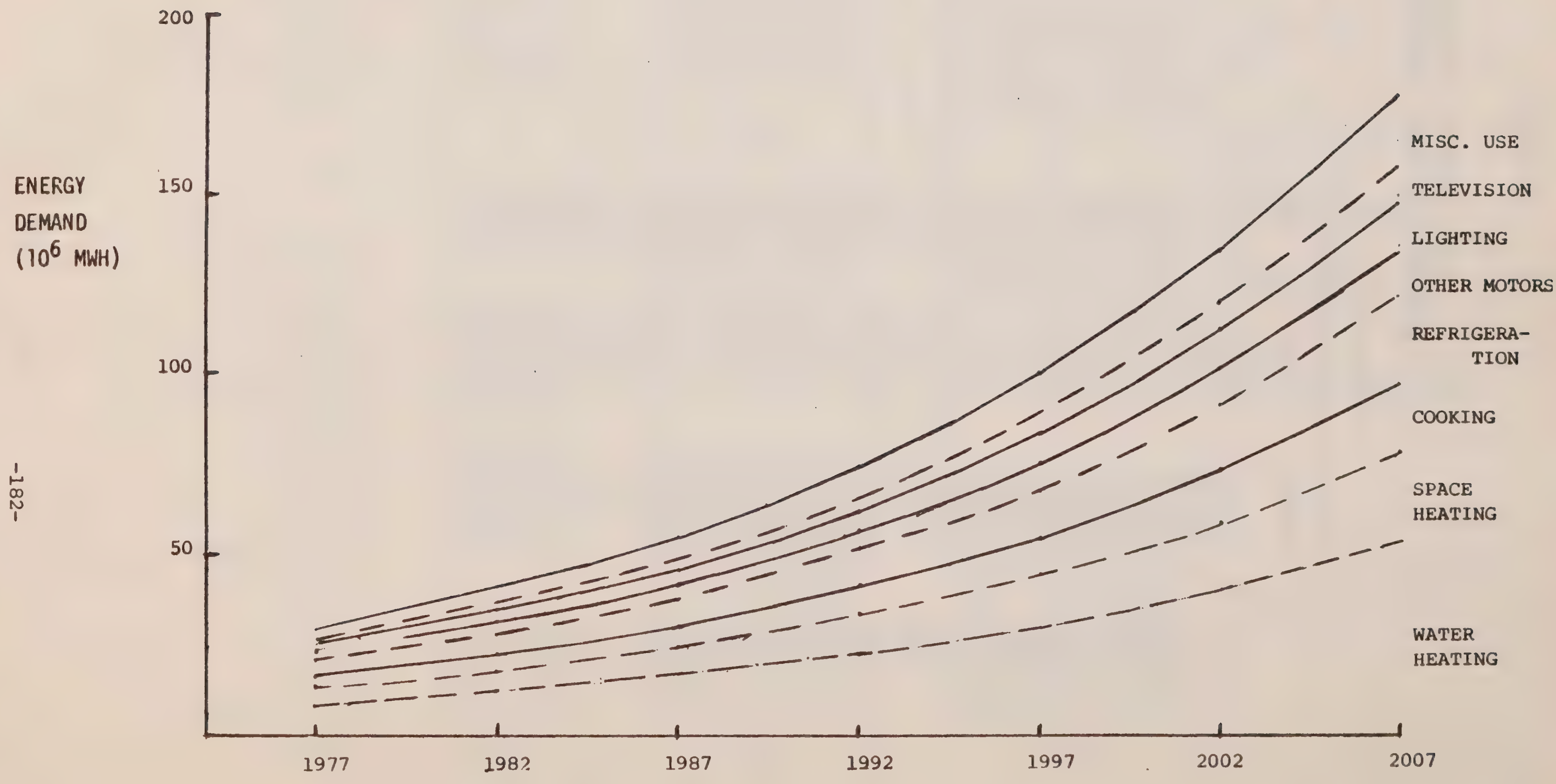


FIGURE 3

ONTARIO INDUSTRIAL ENERGY DEMAND PROJECTION
1977-2007

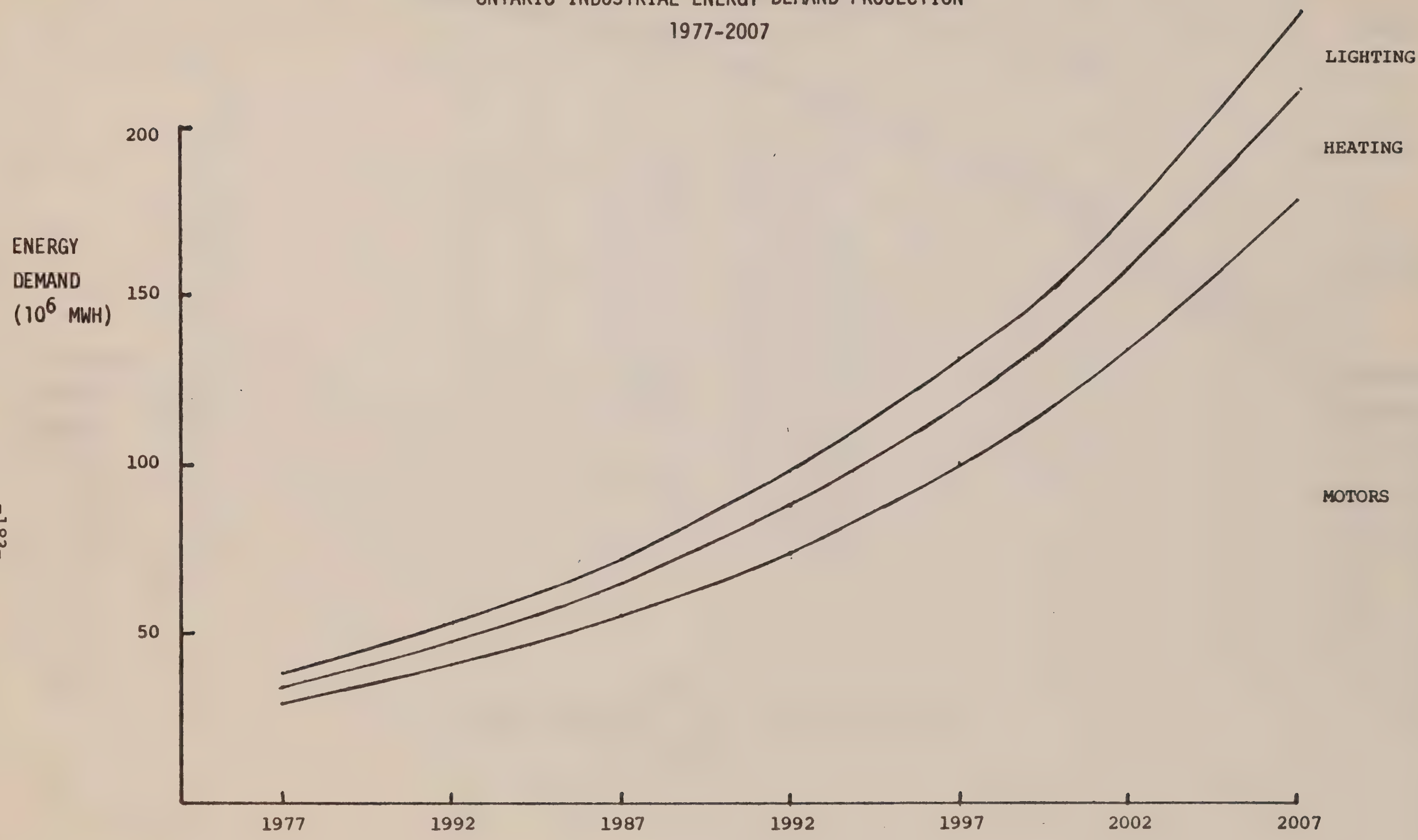
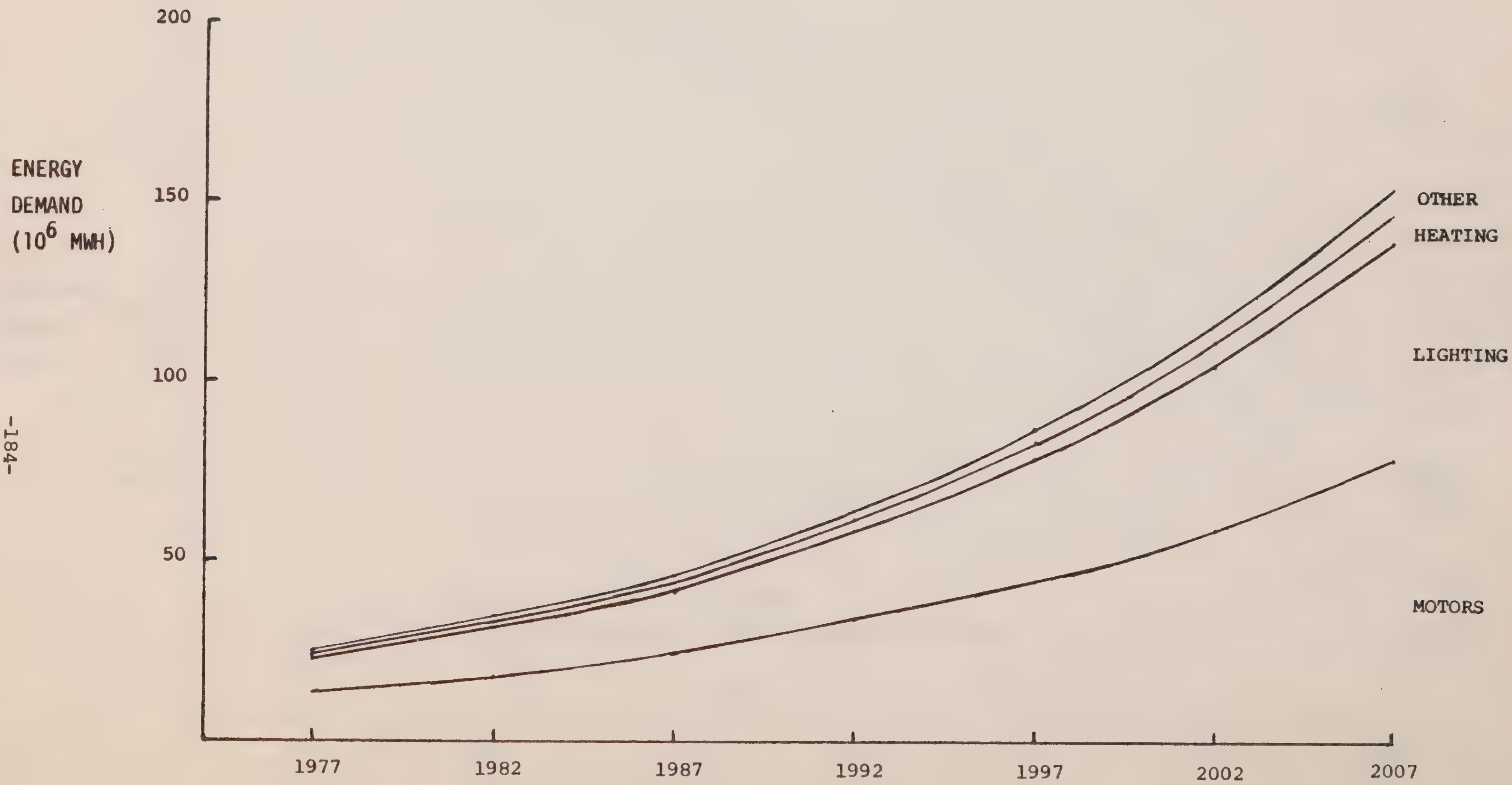


FIGURE 4

ONTARIO COMMERCIAL ENERGY DEMAND PROJECTION

1977-2007



Middleton Associates

Research Consultants
Energy, Resources and Environment

August 24, 1977

Dear

On behalf of Peter Victor, thank you for responding to the questionnaire requesting an estimate of the possible distribution of electricity use in Ontario in a period covering the next 30 years. In Dr. Victor's letter to you, June 16, 1977, he indicated that once completed responses would be aggregated, you would have an opportunity to run through the process a second time.

In the accompanying document you will find the results of the initial responses, a reiteration of the assumptions involved and the blank questionnaire for you to fill out. It is hoped that you will be able to respond to this second questionnaire within the next two weeks.

If you require any further information, call Peter Victor or myself, Jack Lubek, at 961-5136.

Again, thank you for your cooperation.

Yours sincerely,

Jack Lubek

JL:ed

Encl.

980 Yonge Street, Suite 404, Toronto
Canada, M4W 2J9 (416) 961-5136

THE END USE OF ELECTRICITY IN ONTARIO, 1987-2007

SECOND ROUND - QUESTIONNAIRE

I. Purpose

The purpose of the second round of this questionnaire is to obtain estimates of electricity consumption by end use in light of estimates made by others. The conclusions from the first round of estimates are provided in Table 1 to Table 4 for the years 1987, 1997 and 2007. The first figure indicates the average of seven responses while the second figure is the statistical standard deviation, suggesting the extent of agreement of the estimates.

Some of the respondents in the first round have requested confidentiality of their answers. Partly as a result of this request no individual details are being provided from the first round; this implies that results from any individuals are being returned for reference.

To remind you of the basis for the estimates in round one as well as to reiterate the assumptions for round two, the following repeats some of the information provided to you originally.

For the purpose of the study for which this questionnaire is being used, the forecasted, aggregate load growth is accepted as given. Our specific interest is in the distribution of the forecasted load among the residential, commercial and industrial sectors, and among the various end uses within each sector. Accordingly, you are not asked to assess the accuracy of the load forecast but only to state your views on the proportion of the load that you think will be accounted for by each sector and end use. As far as possible your end use forecast should be consistent with the assumptions underlying Ontario Hydro's load forecast, even if you do not agree with these assumptions.

I (a) FIRST ROUND RESULTS

Table 1

What do you think the distribution of electricity use in each market sector will be?

Sector	1966	1971	1974	1987	1997	2007
Residential	28.8	31.0	31.4	30.0,3.6 *	27.3,6.4	24.4,9.1
Commercial	20.3	22.4	27.2	28.4,3.6	30.4,7.3	30.3,9.9
Industrial	50.9	46.6	41.4	41.6,4.2	42.3,7.1	45.3,9.9
Total	100.0	100.0	100.0			

Table 2

What do you think the distribution of electricity among end uses will be in the RESIDENTIAL sector? (See attachment)

End Use	1951	1961	1971	1974	1987	1997	2007
Misc.	8.2	5.3	5.4	7.3	8.2,2.4	9.5,2.4	9.5,4.4
Clothes Drying	0.0	2.7	4.1	4.3	4.7, .8	4.2,1.3	4.2,1.8
Air Cond.	0.0	0.0	0.7	1.0	2.1,1.3	3.0,2.1	4.1,3.2
TV	2.8	4.5	4.8	5.2	5.5,1.2	5.8,2.4	6.1,3.9
Lighting	15.6	10.4	8.6	7.7	7.6,1.3	8.0,3.0	8.8,5.2
Stove Cooking	13.9	12.2	11.4	10.7	9.8,1.6	10.4,4.2	10.7,6.4
Refrigeration	6.7	9.4	14.8	13.8	12.9,2.1	12.9,4.9	13.4,7.8
Space Heating	5.3	4.7	17.8	20.2	23.7,4.3	25.8,13.6	28.4,22.9
Water Heating	47.5	50.8	32.4	29.8	25.4,1.4	20.2,4.1	15.0,9.3
Total	100.0	100.0	100.0	100.0			

* The first number represents the average for seven responses while the second number represents the statistical standard deviation.

Table 3

What do you think the distribution of electricity among end uses will be in the COMMERCIAL sector?

End Use	1974	1987	1997	2007
Motors	51.0	52.3,2.1	52.3,6.9	52.1,12.5
Heating	5.8	6.4,3.3	9.0,8.0	11.4,13.6
Lighting	38.8	36.1,3.4	32.6,4.6	29.3, 6.3
Other	4.4	5.1,1.2	6.1,2.2	7.1, 3.1
Total	100.0			

Table 4

What do you think the distribution of electricity among end uses will be in the INDUSTRIAL sector?

End Use	1974	1987	1997	2007
Motors	76.1	75.3,2.2	73.1,5.8	70.1,12.4
Heating	13.7	14.6,2.1	16.9,7.2	19.4,15.0
Lighting	10.2	9.6,1.0	8.9,1.9	8.1, 3.0
Other	0.0	0.6,0.8	1.1,1.6	1.7, 2.4
Total	100.0			

III SECOND ROUND QUESTIONS

Please respond to these questions by writing percentage figures in the various tables.

Question 1

What do you think the distribution of electricity use in each market sector will be?

Sector	1966	1971	1974	1987	1997	2007
Residential	28.8	31.0	31.4			
Commercial	20.3	22.4	27.2			
Industrial	50.9	46.6	41.4			
Total	100.0	100.0	100.0			

Question 2

What do you think the distribution of electricity among end uses will be in the RESIDENTIAL sector? (See attachment)

End Use	1951	1961	1971	1974	1987	1997	2007
Misc.	8.2	5.3	5.4	7.3			
Clothes Drying	0.0	2.7	4.1	4.3			
Air Cond.	0.0	0.0	0.7	1.0			
TV	2.8	4.5	4.8	5.2			
Lighting	15.6	10.4	8.6	7.7			
Stove Cooking	13.9	12.2	11.4	10.7			
Refrigeration	6.7	9.4	14.8	13.8			
Space Heating	5.3	4.7	17.8	20.2			
Water Heating	47.5	50.8	32.4	29.8			
Total	100.0	100.0	100.0	100.0			

Question 3

What do you think the distribution of electricity among end uses will be in the COMMERCIAL sector?

End Use	1974	1987	1997	2007
Motors	51.0			
Heating	5.8			
Lighting	38.8			
Other	4.4			
Total	100.0			

Question 4

What do you think the distribution of electricity among end uses will be in the INDUSTRIAL sector?

End Use	1974	1987	1997	2007
Motors	76.1			
Heating	13.7			
Lighting	10.2			
Other	0.0			
Total	100.0			

CONFIDENTIALITY

Do you wish your response to be confidential (please circle appropriately)?

YES NO

APPENDIX B

ONTARIO HYDRO'S GENERATION PROGRAM

LRF 48A

ONTARIO HYDRO EAST SYSTEM

GENERATION PROGRAM LRP48A

Feb 23, 1977

Year	Arnprior	Hydro Quebec	Nant	Lennox	Bruce	BHWP	Steam Plant	Wes	Pick	Bruce	Darl	E-15	E-16	E-17	E-18	E-19	E-20	E-21	E-22	E-23	E-24	E-25	E-26	E-27	E-28
	Hydro	Purch	7-8	4	1-4			1-4	5-8	5-8	1-4	NUC	NUC	FOS	FOS	NUC	NUC	FOS	NUC	FOS	NUC	FOS	NUC	FOS	NUC
			2x531	1x547	4x746			4x547	4x516	4x769	4x850	4x516	4x850	4x750	4x750	4x850	4x1200	4x750	4x1200	4x750	4x1200	4x750	4x1200	4x750	4x1200
1977	Mar 99	Jun -1000	Jul Aug	Feb	July Nov		A Sep																		
1978					Aug		Feb Aug																		
1979					Aug		Feb																		
1980						B Jan																			
1981						D Jul		Dec	Apr																
1982							B Jun	Jul	Jan Oct																
1983							Apr	Feb Aug	Jul	Oct															
1984							Feb Dec			Jul															
1985										Apr	Nov														
1986										Jan	Aug														
1987											Aug	Jul													
1988											Feb	Apr	Jul												
1989												Jan Oct	Apr	Jan Oct											
1990													Jan Oct	Jul	Oct										
1991														Apr	Jul	Jan Oct									
1992															Apr	Jul	Oct								
1993															Jan	Apr	Jul	Jul							
1994																	Apr	Apr	Oct						
1995	E29	E30	E31	E32	E33	E34	E35	E36	E37	E38	E39	E40	E41	E42			Jan	Jan Oct	Jul	Jan Oct					
1996	FOS	NUC	FOS	NUC	FOS	NUC	FOS	NUC	FOS	NUC	FOS	NUC	FOS	NUC					Apr	Jul	Jan Oct	Jul			
1997	4x750	4x1200	4x750	4x2000	4x750	4x2000	4x750	4x2000	4x750	4x2000	4x750	4x2000	4x750	4x2000					Jan	Apr	Jul	Apr	Oct		
1998																					Apr	Jan Oct	Jul	Oct	
1999	Oct																						Apr	Jul	Jan Oct
2000	Jul	Jul																					Jan	Apr	Jul
2001	Apr	Apr	Jan Oct																					Jan	Apr
2002	Jan	Jan Oct	Jul	Jan Oct	Jul																				
2003			Apr	Jul	Apr	Jul																			
2004				Apr	Jan Oct	Apr	Jan Oct																		
2005						Jan Oct	Jul	Oct	Oct																
2006							Apr	Jul	Jul	Jan Oct	Oct	Oct													
2007								Apr	Apr	Jul	Jul	Jul	Jan Oct												
2008								Jan	Jan	Apr	Apr	Apr	Jul	Oct											

LEGEND:

Site and type committed

Site and type planned

Tentative proposal for long range forecast purposes

TABLE 2

ONTARIO HYDRO WEST SYSTEM Jan 1977

GENERATION PROGRAM LRF48A

Year		W1		W3	W4	W5	W6	W7		
		FOS		FOS	NUC	NUC	NUC	NUC		
		2x155		4x200	4x200	4x200	4x200	4x200		
1977										
1978										
1979										
1980		OCT								
1981		APR								
1982										
1983			APR OCT							
1984			APR OCT							
1985										
1986										
1987				APR						
1988				APR						
1989										
1990										
1991				APR						
1992				APR						
1993										
1994					APR					
1995					APR					
1996					APR					
1997										
1998					APR					
1999						APR				
2000						APR				
2001						APR				
2002						APR				
2003							APR			
2004							APR			
2005							APR			
2006							APR			
2007								APR		

LEGEND:

Site and type committed

Site and type planned

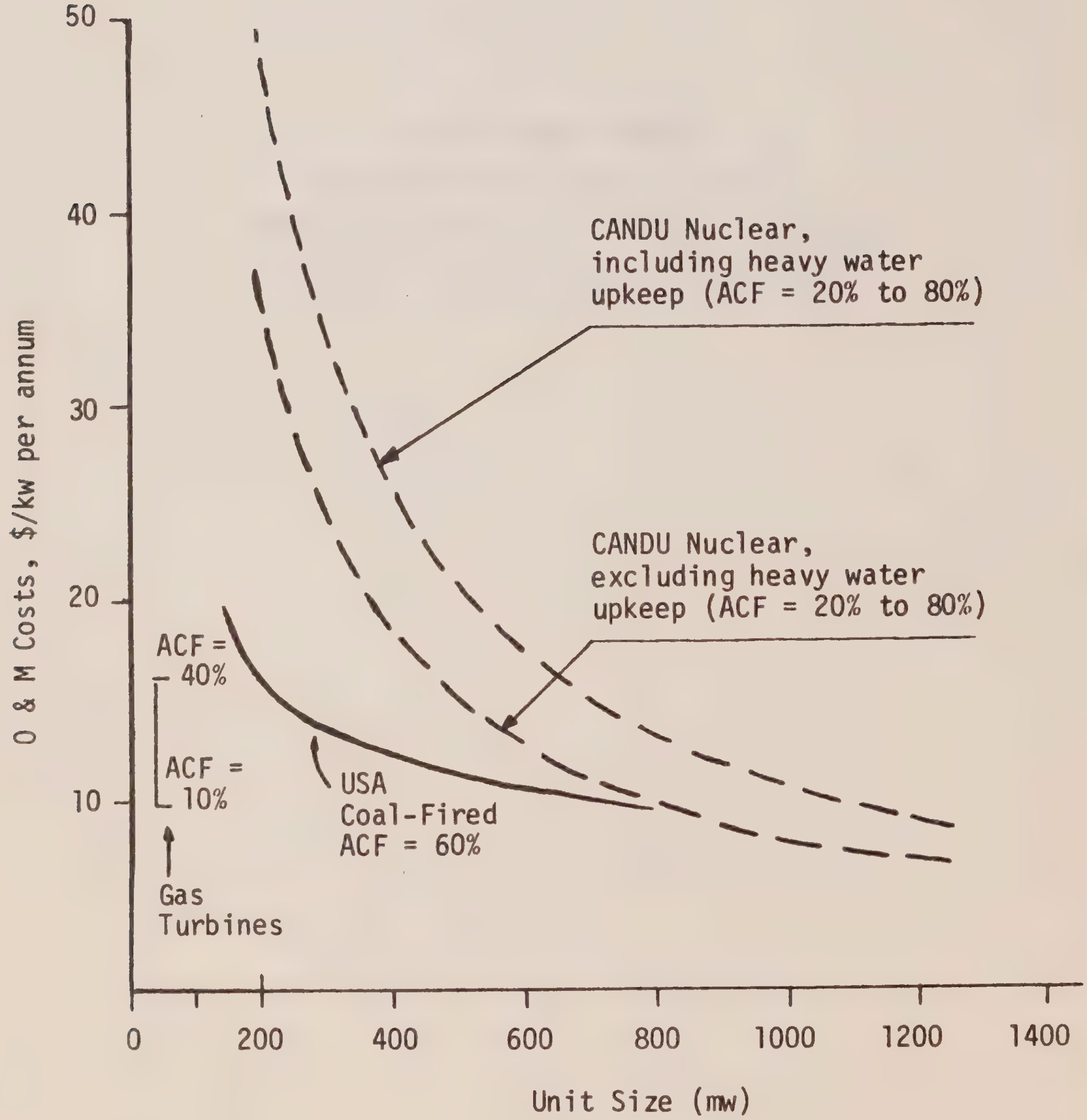
Tentative proposal for long

APPENDIX C

THERMAL GENERATION:
ESTIMATED ANNUAL OPERATIONS AND
MAINTENANCE COSTS IN DOLLARS PER KILOWATT
SENT OUT AT THE GENERATING STATION

THERMAL GENERATION: ESTIMATED ANNUAL OPERATIONS & MAINTENANCE COSTS IN DOLLARS PER KILOWATT SENT OUT AT THE GENERATING STATION

These data apply for 4-unit generating stations and do not include the cost of fuel consumed in the stations.



Source: Ontario Hydro, Generation-Technical, Vol. 1, 1976

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